REVIEW
OF ALTERNATIVE ENERGY SOURCES
AND ELECTRIC POWER UTILITY PROPOSALS

For Cassiar, B.C.

REVIEW OF ALTERNATIVE ENERGY SOURCES AND ELECTRIC POWER UTILITY PROPOSALS FOR CASSIAR, B.C.

Prepared for:

Brinco Mining Limited:

Prepared by:

Brinco Mining Limited
Columbia Pacific Resources Group Ltd.
Crippen Consultants

With a contribution from:

Remote Community Demonstration Program
of Energy, Mines and Resources

December 1984

RCDP/PDCE-44

This report was prepared with a contribution from the Remote Community Demonstration Program of Energy, Mines and Resources Canada (EMR). Distribution of this report by EMR does not necessarily signify that the contents reflect the views and policies of EMR. Mention of trade names and commercial products does not constitute recommendation or endorsement for use.

TABLE OF CONTENTS

		Page No.
Abbreviations		5
Summary		6
Résumé		9
1.	Introduction	
	1.1 Background	13
	1.2 Energy Considerations	13
	1.3 Study Scope	13
2.	Current Energy Supply System	
	2.1 Energy Demand and Supply	15
	2.2 Price Forecast for Diesel Fuel and Lubricants	17
	2.3 Electrical Energy Demand	18
	2.4 Base Case - Continuation of Diesel Generation	19
3.	Proposed Future Energy Supply System	
	3.1 Hydroelectric Alternatives	22
	3.2 Alternate Energy Sources	23
	3.3 Energy Conservation	29
	3.4 Social Benefit Cost Analysis of Small Hydro Development	29
	3.5 Socio-Economic and Environmental Impact Considerations for Small Hydro Development	33
4.	Proposal for a Regional Small Hydro Utility	
	4.1 Corporate Structure and Financing Alternatives	38
	4.2 Utility Cost of Service and Rate Analysis	39
	4.3 Government Regulatory Implications	44
	4.4 Summary	60
5.	Conclusions	62

LIST OF TABLES & FIGURES

Tables		Page No
2.1	Forecast of Diesel Fuel Price for the Cassiar Mine	18
2.2 Parts 1 & 2	Base Case, Electrical General Using Diesel	20 & 21
3.1 Parts 1 & 2	Regional Utility with 7.5 MW Hydro Project, Implementation July 1987	25 & 26
3.2 Parts 1 & 2	Regional Utility with 12 MW Hydro Project, Implementation July 1988	27 & 28
3.3	Benefits and Costs of Small Hydro Development	30
3.4	Benefit Cost Assumptions for Small Hydro Project for the Cassiar Mine	32
3.5	Preliminary Social Benefit Cost Analysis of Small Hydro Development for Cassiar Mine	33
3.6	Summary of 1983 Direct Employment and Estimated Indirect and Induced Employment	35
3.7	Estimated 1983 Direct, Indirect and Induced Labour Income	36
4.1 Parts 1 & 2	Utility Revenue Requirement: Scenario Diesel	46-49
4.2 Parts 1 & 2	Utility Revenue Requirement: Scenario 7.5 MW Hydro	50-53
4.3 Parts 1 & 2	Utility Revenue Requirement: Scenario 12 MW Hydro	54-57
4.4	Sensitivity Analysis - 7.5 MW Hydro	59
Figures		
1.1	General Plan of Cassiar Region	64
3.1	12 MW Development - Preliminary Layout	65
3.2	7.5 MW Development - Preliminary Layout	66
Graphs		
	Cassiar Unit Cost Graph; Diesel, 7.5 MW Hydro and 12 MW Hydro	68

LIST OF ABBREVIATIONS

BCUC	British Columbia Utilities Commission
B.C.	British Columbia
CCA	Capital Cost Allowance
DFO	Department of Fisheries and Oceans (Federal)
D.O.H.	Department of Highways (Provincial)
EOY	End of Year
EPCA	Energy project certificate application
FOY	First of Year
IRR	Internal Rate of Return
MOE	Ministry of Environment (Provincial)
MEMPR	Ministry of Energy Mines and Petroleum Resources (Provincial)
NCPC	Northern Canada Power Commission
O & M	Operation & Maintenance

bbl	Barrel
BTU	British Thermal Unit
GW.h	Gigawatt-hours (1 GW.h = 10^6 kW.h)
kW	Kilowatts
kW.h	Kilowatt-hour
L	Litre
MW	Megawatts (1000 kilowatts = 1 MW)

SUMMARY

Introduction

This report describes the electrical energy supply options for the community of Cassiar which is located in northwestern British Columbia. The major activity at Cassiar is the asbestos mine and mill owned and operated by Brinco Mining Limited. Brinco employs approximately 410 persons out of the total community population of 1400. Besides the Cassiar asbestos activities, there are two small producing gold mines and a Ministry of Highways maintenance facility located in the immediate vicinity.

The townsite also forms a regional centre with police, education and hospital facilities established there.

The supply of electrical energy to the mine, mill and townsite has been a significant cost factor for Brinco. The company operates an all diesel power plant which has an annual diesel fuel requirement of approximately 17 million litres costing approximately $6 million per year. Since the late seventies, Brinco have sought to reduce their energy costs by investigating alternative sources of supply and by instituting an aggressive energy conservation program.

This report describes three aspects of energy supply for the Cassiar region. Firstly, the current energy supply situation is described and projections of electrical energy production by continued use of diesel plant are made. Secondly, alternative energy sources are reviewed and the most promising available hydroelectric sites are examined. Hydro-site development costs are updated and a benefit-cost analysis is described for two hydroelectric development options. Thirdly, the concept of a regional utility is examined. Corporate structure and financing alternatives are described, and utility cash flows based on the development of hydroelectric sites are given. The effects of Government regulatory requirements on a utility scaled to meet regional requirements are discussed.

Energy Supply Alternatives

At present the annual energy requirements of the Cassiar region are met by importation of diesel fuel and propane as shown below:

	Amount (litres)	$	% Total Cost
Diesel fuel - power generation	17 000 000	6 500 000	57%
Fuel - heating	12 000 000	4 600 000	40%
Propane - heating	420 000	300 000	3%
		11 400 000	100%

The diesel powerplant installed capacity at Cassiar is 12 MW and at other mines and facilities is 3 MW. Combined regional electrical energy demand is 59 million kW.h/year.

Past and present investigations into reducing energy costs have enabled the following conclusions to be drawn.

i) It is unlikely that the B.C. Hydro grid will be extended to Cassiar until the Iskut/Stikine system is developed (at least 15 years in the future) or until the development of other major mines leads to substantially increased regional demand.

ii) Wood waste, natural gas, nuclear and coal fired thermal do not appear to be viable alternate energy sources at present.

iii) Several hydroelectric sites in the vicinity of Cassiar have been investigated, the most promising of which are located on the Cottonwood River approximately 40 km southwest of the town of Cassiar. Two development alternatives, one of 7.5 MW capacity costing $39.9 million, and the other of 12 MW capacity costing $61.5 million were studied for this report. The 7.5 MW project can supply approximately 88% of the regional electrical demand whereas the 12 MW project can supply approximately 96% of the regional electrical demand. Under current day economic conditions the 7.5 MW project can supply energy in the short term at approximately the same unit cost as energy generated by diesel plant. In the long term, hydroelectric unit energy costs will be significantly less than diesel generation unit costs.

iv) It is unlikely that hydroelectric energy will displace fuel oil for heating purposes. The current energy conservation program being run by Brinco should therefore be continued in order to minimize heating fuel costs.

v) Social benefit-cost analysis of the hydroelectric alternatives, conducted from the viewpoint of Canadian social interests, indicates internal rates of return of 17% for the 7.5 MW project and 8% for the 12 MW project. From the national viewpoint 7.5 MW project appears viable on the basis of petroleum fuel substitution alone.

vi) Hydroelectric development of the Cottonwood River is unlikely to cause significant wildlife and fisheries damage. If access to recreation facilities is taken into account, the net environmental impact will be considered positive by a large percentage of local inhabitants.

Regional Utility Alternatives

Alternative organizational structures for a regional utility can have differential tax and financing implications which could prove significant in initiating a project of this type. The conventional utility structure may be less attractive in terms of the level of equity financing required by the proponent and the potential absence of certain tax write-offs (e.g. investment tax credit). On the other hand, the conventional structure could be more successful in attracting new customers, in obtaining suitable financing and in dealing with government and regulatory officials on tax and policy matters.

The financial analysis of the existing diesel and small hydro options, assuming a conventional utility structure, indicates that the 7.5 MW project is preferable under a base case which assumes existing tax law and Class 34 CCA's. The relative advantage of the 7.5 MW project under the base case erodes without the Class 34 CCA's. On the other hand, the relative advantage of 7.5 MW project under the base case improves markedly with assumed reductions in taxes (property taxes, water licence fees) and the utility's cost of capital.

The review of regulatory implications of a regional small hydro utility indicates the requirement for a long term commitment to service regardless of the organizational structure. The utility's exemption status from regulation requires evidence that the small hydro project is economically efficient, ensures continuity of service (particularly to third parties), applies non-discriminatory prices, is financially feasible, and is environmentally acceptable. These requirements certainly imply a social responsibility for providing continuous service over the long term. Private sector proponents should recognize the limits placed on their flexibility in terms of curtailing or eliminating service in the event that it became privately (rather than socially) desirable to do so.

EXAMEN DES SOURCES D'ÉNERGIE DE RECHANGE DES PROPOSITIONS DE PRODUCTION D'ÉNERGIE ÉLECTRIQUE POUR CASSIAR (COLOMBIE-BRITANNIQUE)

Résumé

Le présent rapport décrit les options en matière de production d'énergie électrique pour la collectivité de Cassiar, située dans le nord-ouest de la Colombie-Britannique. La mine et l'usine de traitement d'amiante exploitées par la Brinco Mining Limited constituent la principale activité économique de la collectivité. Environ 410 personnes d'une population totale de 1 400 habitants sont employées par la Brinco. Outre les activités liées à l'amiante, on exploite à Cassiar deux petites mines d'or et il y a une installation d'entretien du ministère de la Voirie dans le voisinage immédiat.

La collectivité constitue aussi un centre régional où se trouvent des installations de la police, des écoles et un centre hospitalier.

La production de l'énergie électrique destinée à la mine, à l'usine et à la collectivité elle-même représente un coût important pour la Brinco. La société exploite une centrale électrique alimentée au diesel qui consomme annuellement quelque 17 millions de litres de carburant diesel au coût d'environ 6 millions de dollars par an. Depuis la dernière partie des années 70, la Brinco fait des efforts pour réduire les frais d'énergie en examinant des sources d'énergie de rechange et en adoptant un programme dynamique d'économie d'énergie.

Le présent rapport décrit trois aspects de l'approvisionnement énergétique pour la région de Cassiar. En premier lieu, il décrit la situation actuelle de l'approvisionnement énergétique et propose des projections relatives à la production d'énergie électrique à l'aide de la centrale diesel. En deuxième lieu, il examine les différentes sources d'énergie de rechange et les sites les plus prometteurs d'aménagement hydro-électrique. Il fait la mise à jour des coûts de mise en valeur des sites hydro-électriques et décrit une analyse des coûts-avantages de deux options d'aménagement hydro-électrique. En troisième lieu, il examine la notion d'un service public régional d'électricité. La description des options en matière de structure sociétaire et de financement est suivie d'une estimation des flux de trésorerie pour les deux possibilités d'aménagement hydro-électrique. Le rapport examine les effets des exigences de la réglementation gouvernementale sur un service public adapté aux besoins de la région.

Options d'approvisionnement énergétique

À l'heure actuelle, les besoins annuels en énergie de la région de Cassiar sont satisfaits par l'importation de carburant diesel et de propane:

	Volume (en litres)	Coût (en dollars)	Pourcentage du coût total
Carburant diesel - production d'électricité	17,000,000	6,500,000	57
Mazout - chauffage	12,000,000	4,600,000	40
Propane - chauffage	420,000	300,000	3
		11,400,000	100

La puissance installée de la centrale diesel à Cassiar est de 12 MW et celle des autres mines et installations connexes est de 3 MW. La demande annuelle d'énergie électrique de la région s'élève à 59 millions de kilowatts-heures.

Les conclusions suivantes sont tirées des études antérieures et actuelle sportant sur la réduction des frais d'énergie.

1. Il est peu probable que le réseau de la B.C. Hydro soit prolongé jusqu'à Cassiar avant l'aménagement du système de la région Iskut/Stikine (au plus tôt dans 15 ans) ou avant le moment où la mise en valeur d'autres grandes mines entraîne un accroissement sensible de la demande régionale.

2. Les centrales alimentées aux déchets de bois, au gaz naturel, les centrales nucléaires ou les centrales thermiques alimentées au charbon ne semblent pas présenter des options viables pour le moment.

3. Plusieurs sites hydro-électriques à proximité de Cassiar ont été examinés; les meilleurs sont situés sur la rivière Cottonwood à quelque 40 kilomètres au sud-est de l'agglomération de Cassiar. La présente étude a examiné deux possibilités de mise en valeur, dont l'une concerne une puissance de 7,5 MW au coût de 39,9 millions de dollars, et l'autre une puissance de 12 MW au coût de 61,5 millions de dollars. Le projet de 7,5 MW peut satisfaire environ 88 % de la demande d'électricité de la région, tandis que le projet de 12 MW peut satisfaire environ 96 % de la demande régionale. Dans les conditions économiques actuelles, le projet de 7,5 MW peut fournir de l'énergie électrique à court terme à un coût unitaire approximativement égal à celui de l'installation diesel. À long terme, les coûts unitaires de l'énergie hydro-électrique seraient sensiblement inférieurs aux coûts unitaires de l'énergie produite au diesel.

4. Il est peu probable que l'énergie hydro-électrique remplace le mazout pour le chauffage des locaux. Le programme actuel d'économie d'énergie mis en oeuvre par la Brinco devrait donc se poursuivre afin de réduire le plus possible les frais de chauffage.

5. L'analyse des coûts-avantages sociaux des options hydro-électriques, menée du point de vue des intérêts sociaux du Canada, donne des taux de rendement interne de 17 % pour le projet de 7,5 MW et de 8% pour le projet de 12 MW. À l'échelon national, le projet de 7,5 MW semblerait viable rien que du point de vue du remplacement du pétrole.

6. L'aménagement hydro-électrique de la rivière Cottonwood ne devrait pas entraîner des dommages sensibles à la faune ou aux pêches. Si l'on tient compte de l'accès aux loisirs, les incidences environnementales nettes seront jugées positives par un grand pourcentage des habitants de la localité.

Options en matière de service public régional

Les différentes structures d'organisation d'un service public régional peuvent entraîner des effets fiscaux et financiers de première importance pour le lancement d'un projet de ce genre. La structure traditionnelle de services publics peut être moins intéressante en ce qui concerne la mise de fonds par le promoteur et l'absence éventuelle de certains amortissements fiscaux (par exemple le crédit d'impôt pour l'investissement). D'autre part, la structure traditionnelle pourrait connaître plus de succès en ce qui concerne l'adhésion de nouveaux clients, l'obtention d'un financement convenable et les relations avec les fonctionnaires et les organes de réglementation sur des questions de fiscalité et de politique.

L'analyse financière des options relatives aux petites installations hydro-électriques et à la centrale diesel existante, dans l'hypothèse d'une structure traditionnelle de services publics, indique que le projet de 7,5 MW est préférable dans le cas fondamental qui prend pour hypothèse la loi actuelle sur les impôts et les déductions pour amortissement de catégorie 34. L'avantage relatif du projet de 7,5 MW dans l'hypothèse de base diminue sans les déductions pour amortissement de catégorie 34. D'autre part, l'avantage relatif du projet de 7,5 MW dans l'hypothèse de base s'améliore nettement si l'on tient compte des réductions d'impôt (taxes foncières, droits relatifs aux permis d'exploitation des eaux) et du coût du capital pour le service public.

L'examen des effets de la réglementation sur une petite centrale hydro-électrique régionale indique qu'il est nécessaire de compter sur un engagement à long terme, quelle que soit la structure d'organisation. Pour que le service public bénéficie d'exemptions à l'égard de la réglementation, il faut prouver que le projet hydro-électrique est efficace du point de vue économique, qu'il assure la continuité du service (notamment aux tiers), qu'il applique des tarifs non discriminatoires, qu'il est rentable, et qu'il est acceptable du point de vue de l'environnement. Ces exigences entraînent certes une responsabilité sociale en ce qui concerne un service continu à long terme. Les promoteurs du secteur privé devraient reconnaître les limites imposées sur leur souplesse d'action en ce qui concerne une réduction ou la suppression du service au cas où il deviendrait souhaitable de prendre de telles mesures d'un point de vue particulier (plutôt que social).

La présente étude a été menée pour la Brinco Mining Limited par la Brinco et les firmes Columbia Pacific Resources Group Limited et Crippen Consultants à l'aide d'un contribution offerte par le Programme de démonstration dans les collectivités éloignées d'Énergie, Mines et Ressources Canada.

1. INTRODUCTION

1.1 Background

Cassiar is an unincorporated mining community situated in Northwestern British Columbia (lat 59° 17', long 129° 50', NTS 104 P/5) approximately 130 km south of the B.C.-Yukon border. Current population in the Cassiar townsite is approximately 1,400 and the area population within a 25 km radius is approximately 2,000. The economic base at present is asbestos mining and gold mining; asbestos mining is the major activity, with the Cassiar operation of Brinco Mining Limited constituting the largest employer in the community.

Open pit asbestos mining at Cassiar began in 1952 and continues to this day. Open pit mining is expected to continue until 1990, at which time the operation will shift to underground mining or tailings treatment options.

Besides current mining activities, there are numerous significant deposits of base metal ores in the area as well as several known mineral occurences.

1.2 Energy Considerations

All mining operations, office and residential energy requirements in the Cassiar area are currently met by liquid petroleum energy sources. Fuel oil and diesel fuel provide most of the electrical and heating needs, with limited use of propane. Shipping liquid fuels to the remote Cassiar location results in high energy costs. Besides instituting an active energy conservation program, Brinco have over the years undertaken investigations into alternative sources of energy. Hydroelectric, piped natural gas, and connection to the B.C. Hydro grid have been considered. Thermal and nuclear energy sources have also been considered. B.C. Hydro have stated that they are unable to take on the utility role in the region. Up to the present time, none of the alternatives have proved economically viable for Brinco. Incentives for the development of alternate local energy sources may however be available to a regional utility if a suitable utility structure and financial environment can be found. The purpose of this report is to examine the benefit-cost of alternative energy sources and to examine the alternatives which are available for the evolution of a regional utility to serve the area.

1.3 Study Scope

The study was structured in three phases. Firstly the current energy supply system was examined to establish a base case scenario in which it is assumed that present energy sources will be utilized in the future. Secondly alternate energy sources were examined and the most promising alternative source was selected for cost benefit evaluation. The purpose of this second phase was to determine whether the development of alternative energy sources is viable from the wider social perspective. The third phase consisted of an examination of the financial and regulatory climate within which a regional utility could be established. In this phase, the effectiveness of various utility structures and current energy incentive programs towards development of alternate energy sources at Cassiar was shown. Finally, the study focused on planning issues for corporations, local bodies, and senior government in their

efforts to achieve mutually advantageous energy supply objectives for the community.

One of the objectives of the study was that it will serve as a model for future studies at similar remote locations without access to a major established power grid.

2. CURRENT ENERGY SUPPLY SYSTEM

2.1 Energy Demand and Supply

Space heating, process heating and electrical energy demand at Cassiar occurs from the following facilities:

a) Cassiar Asbestos Mine Operation and Townsite (Population 1400)

- Open Pit Mine
- Mill (where asbestos fibre is dried, processed and packaged)
- Mine offices, workshops, storage buildings, etc.
- Commercial and Administrative
- Residential/Bunkhouses
- Municipal Facilities

b) Erickson, Taurus Gold Mines (Population 150)

- Mine and Mill
- Residences/Bunkhouses

c) Department of Highways (Population 12) plus Indian Reserve and School (Population 70)

- Maintenance Facility
- Residences/Bunkhouses

The energy requirements for a typical year in the period 1980 to 1983 were as follows:

	Diesel & Fuel Oil	Propane
Cassiar	25 500 000 litres	300 000 kg
Erikson, Taurus and Provincial D.O.H.	3 500 000 litres	120 000 kg
	29 000 000 litres	420 000 kg

Of the above diesel and fuel oil quantities, approximately 62 percent (17 000 000 litres) is used for diesel generation of electricity and the remainder is used for process and space heating. The annual fuel cost component of generating electricity amounts to approximately $6.5 million.

At the Cassiar mine, waste heat is recovered from diesel generating facilities through exhaust gas and coolant recovery systems. The fuel oil equivalent of waste heat recovery is difficult to assess owing to the lack of direct measurement facilities. It is, however, estimated to be between one and two million litres of fuel per year, representing 7 to 14% recovery on fuel used in the Cassiar powerplant. Waste heat from the engine jacket coolant is used to supplement fuel oil heating used in the asbestos fibre driers. Waste heat from the engine exhaust produces steam which is used to heat mine buildings and some of the townsite residences and offices. Taurus or Erickson mines do not have waste heat recovery facilities.

Current electrical energy demand at Cassiar is divided between the various sectors as follows:

Mine	13%
Mill	59%
Mine maintenance Facilities	10%
Townsite	18%

While it was not possible to obtain a detailed breakdown for the smaller Erickson and Taurus mines, it is likely that mining operations demand a large share of energy generated. It should be noted that the Cassiar mining operation supplies electrical power to government and service sector demands such as the R.C.M.P., Provincial Government offices, retail, health and education facilities.

The electrical generating plant (diesel) presently installed in the region consists of the following:

Cassiar:

10 -	Ruston 9 ATC Engines Rated Capacity 10 x 1370 =	13 700	kW
1 -	Mirrlees KL SS-5	1 000	kW
	Total	14 700	kW

Other

Erickson installed capacity	2 100	kW
Taurus	700	kW
Department of Highways	165	kW
Total	2 965	kW

Most of the diesel generating units installed at the Cassiar powerplant are old units nearing the end of their economic life. The annual cost of keeping these units in operation stated to be $800 000 to $1 000 000 for maintenance costs and $600 000 for operating costs. Estimates of maintenance and operating costs for other generating units at Erickson, Taurus and Department of Highways were not available.

The installed capacity at Cassiar is adequate to meet peak demands. Powerhouse logs show that peak demand is generally around 8 MW, rarely exceeding 9 MW. Theoretically, there is generous excess capacity, however in practice, one or two units are down for overhaul most of the time. With the proposed change from open pit mining to an underground operation, it is expected that Cassiar powerplant peak demands will moderate as the large mine shovels will be taken out of service and underground facilities will consist of smaller electric motors with smaller demand fluctuations. Energy demands are however expected to remain without significant change.

2.2 Price Forecast for Diesel Fuel and Lubricants

A price forecast for diesel fuel has been developed based on projected trends in world crude oil prices, domestic crude oil prices, diesel refining costs and diesel transporations costs from Vancouver to the Cassiar mine. The diesel fuel price forecast is developed in constant 1984 prices (real terms) and is presented in Table 2.1 for the period to 2005 commencing in 1987, the first year of potential diesel fuel displacement by a small hydro scheme.

The current (1984) world crude oil price of $31.00 U.S. per barrel is projected to decline slightly in real terms to $29.50 U.S. per barrel in 1985 and remain at that level until the early 1990's. In the early 1990's, it is projected that world crude oil prices will grow at a real rate of one (1) percent per annum resulting in a real price of $33.93 U.S. per barrel by 2005.

The projection of domestic crude oil prices assumes that domestic prices will be equivalent to world prices, excepting for exchange rate differences, over the forecast period. The Canadian-U.S. exchange rate is assumed to be near or at the 0.80 level over the forecast period.

Canadian refining costs for diesel fuel are estimated at 9 cents per litre and are projected to track the average inflation rate over the forecast period. Transporation costs for diesel fuel from Vancouver to the Cassiar mine are estimated to average 5.5 cents per litre and are assumed to remain constant in real terms over the forecast period.

These assumptions result in a diesel fuel price forecast of 38 cents per litre in the initial years of the forecast period rising to 41 cents per litre by the year 2005.

The price of oil lubricants is assumed to track the average inflation rate over the forecast period. Hence, the 1984 price of $1.45 per litre is projected to remain constant in real terms over the period to 2005.

TABLE 2.1
FORECAST OF DIESEL FUEL PRICE
FOR THE
CASSIAR MINE

	(1984 constant dollars)				
	1987	1990	1995	2000	2005
World Crude (U.S. $/bbl)	29.50	29.50	30.70	32.28	33.93
Canada-U.S. Exchange Rate	0.79	0.80	0.80	0.80	0.80
Domestic Crude (Cdn $/bbl)	37.34	36.88	38.38	40.35	42.41
Domestic Crude (Cdn $/L)	0.235	0.232	0.241	0.254	0.267
Diesel Margin (Cdn $/L)	0.090	0.090	0.090	0.090	0.090
Diesel @ Vancouver Refinery (Cdn $/L)	0.325	0.322	0.331	0.344	0.357
Transportation Vancouver - Cassiar (Cdn $/L)	0.055	0.055	0.055	0.055	0.055
Price of Displaced Diesel (Cdn $/L)	0.380	0.377	0.386	0.399	0.412

2.3 Electrical Energy Demand

Electrical demands have been estimated for both energy and capacity requirements. Table 2.2 shows energy demand estimates broken down into figures for Cassiar and for other consumers. The estimates for Cassiar take into account the future changes in mine operation from open pit to underground. The scenario for this report envisages cessation of open pit operations in 1989, three years of tailings retreatment 1990 to 1992, and full production of McDame underground from 1993 on. An energy demand forecast for other generating units in the region could not be accurately determined so no growth was assumed.

Current peak capacity demand at Cassiar is approximately 9 000 kW, representing 60% of installed capacity. Not all of the installed capacity is available due to one or two machines being down for maintenance. Apart from the need to replace the three oldest existing diesel units, there is, at present, adequate equipment to meet future capacity demands. The future change to underground mining operations will result in a slight lowering of peak demands.

If abundant hydroelectric energy were to be available, conversion to electric heating may be considered. Electric heating is however unlikely to be economic at Cassiar. Heating fuel costs at Cassiar give a price of approximately 1.3 cents/1000 BTU based on 80% efficiency. Electric costs would have to be close to 4.5 cents per kW.h to be competitive. It is unlikely that hydro energy can be supplied cheaper than 8 cents/kW.h.

There is no indication at present that substantial changes to energy or capacity demands will occur at the other generating facilities in the region. Taurus anticipate an increase in installed capacity of 200 to 300 kW only.

2.4 Base Case - Continuation of Diesel Generation

Prior to examining alternate energy source options, it is necessary to establish projected costs on the assumption that the present method of generation will be used. Table 2.2 shows the base case cost scenario for the Cassiar region assuming that each of Cassiar and the other generating facilities remain autonomous. The following assumptions are made in establishing the base case:

a) It is unlikely that Brinco will undertake the role of utility for the region if diesel generation continues to be the source of electrical energy. The cost of installing a transmission system to supply the other mines and the Department of Highways cannot be justified unless there are unusual benefits in terms of power supply reliability or centralization of operating costs.

b) For the base case with mine life to 2005 it is assumed that a new 4.5 MW diesel generating unit will be purchased and placed in operation by the end of 1985 to replace aging existing units. Adjustments to fuel and lube oil specific consumption rates will occur after the new unit is brought on line. A further replacement unit is assumed installed in 1995.

TABLE 2.2 - PART I

BASE CASE - ELECTRICAL GENERATION USING DIESEL (1)

Year	Demand			Diesel Fuel(2)		Lube Oil	
	Cassiar GW.h	Other GW.h	Total	Cassiar $Lx10^6$	Other $Lx10^6$	Cassiar $Lx10^6$	Other $Lx10^6$
1979	52.3			15.1		168	
1980	57.4			16.6		156	
1981	49.5			14.7		129	
1982	47.2			14.2		150	
1983	47.5			13.1		144	
1984	46.3	12.83	59.13	13.2	3.95	140	.036
1985	46.3	12.83	59.13	13.2	3.95	140	.036
1986	46.3	12.83	59.13	12.65	3.95	140	.036
1987	45.1	12.83	57.93	12.31	3.95	137	.036
1988	▲	▲	▲	▲	▲	▲	▲
1989							
1990							
1991							
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004	▼	▼	▼	▼	▼	▼	▼
2005	45.1	12.83	57.93	12.31	3.95	137	.036

(1) Autonomous generation at Erickson, Taurus and D.O.H. assumed.

(2) Assumed fuel consumption:

To end 1985: at Cassiar 3.5 kW.h/L, at other sites 3.248 kW.h/L

From 1986 on, at Cassiar after Mirrlees unit replacement generating 30 GW.h/yr assumed rate 3.75 kW.h/L.

TABLE 2.2 - PART 2

BASE CASE - ELECTRICAL GENERATION USING DIESEL

($ x 1 000)

Year	Fuel & Lube Oil(1)		Capital (2)		Operating		Maintenance	
	Cassiar	Other	Cassiar	Other	Cassiar	Other	Cassiar	Other
1979					508		824	
1980					475		1 069	
1981					602		606	
1982					563		808	
1983					607		1 026	
1984	4 955	1 474	-	-	600	100	950	200
1985	↓	↓	3 900	-	▲	▲	950	▲
1986	▼	▼	-	-	↑	↑	575	↑
1987	4 876	1 553	-	-	↑	↑	▲	↑
1988	↓	↓	-	-	↑	↑	↑	↑
1989	▼	▼	-	-	↑	↑	↑	↑
1990	4 839	1 541	-	-	↑	↑	↑	↑
1991	↓	↓	-	-	↑	↑	↑	↑
1992	↓	↓	-	-	↑	↑	↑	↑
1993	↓	↓	-	-	↑	↑	↑	↑
1994	▼	▼	-	-	↑	↑	↑	↑
1995	4 950	1 577	3 900	1 200	↑	↑	↑	↑
1996	↓	↓	-	-	↑	↑	↑	↑
1997	↓	↓	-	-	↑	↑	↑	↑
1998	↓	↓	-	-	↑	↑	↑	↑
1999	↓	↓	-	-	↑	↑	↑	↑
2000	↓	↓	-	-	↑	↑	↑	↑
2001	↓	↓	-	-	↑	↑	↑	↑
2002	↓	↓	-	-	↑	↑	↑	↑
2003	↓	↓	-	-	↑	↑	↑	↑
2004	▼	▼	-	-	▼	▼	▼	▼
2005	5 270	1 680	-	-	600	100	575	200

(1)

Diesel Fuel Historical Costs		Lube Oil Historical Costs	
1979	.17 $/L	1979	.64 $/L
1980	.19	1980	.73
1981	.29	1981	1.09
1982	.34	1982	1.54
1983	.36	1983	1.38

(2) Assumptions:

At Cassiar, one new 4.5 MW Mirrlees Unit installed in 1985 and one in 1995.

At other sites, single replacement assumed in 1995.

3. PROPOSED FUTURE ENERGY SUPPLY SYSTEM

3.1 Hydroelectric Alternatives

Potential hydroelectric sites in the vicinity of Cassiar have been identified and investigated. Smaller sites appropriate to the Cassiar Region demand are confined to McDame Creek, Troutline Creek, Bass Creek and the Cottonwood River, all of which are located west and south of Cassiar and are tributaries of the Dease River. Significant sites examined to date include the following:

a) Various developments on Bass, Troutline and McDame Creeks were examined 1955 to 1960 by Crippen Engineering Ltd. These sites range in capacity from 2 to 4 MW; due to the lack of good storage they can be operated during the summer only.

b) Reconnaissance studies of various sites on the Cottonwood were conducted by Sir William Halcrow & Partners in 1961 and the Water Investigations Branch of British Columbia Water Resources Service in 1965.

c) An office study of Cottonwood River hydro sites was conducted by Crippen in June 1980. Neighbouring catchments (Dease River, Jennings River and Tuya River) were also examined. Based on this study, Cassiar engaged Crippen to carry out a detailed feasibility study of Site 1, 47 km above the confluence of the Cottonwood and Dease River. The project was sized to meet all of the power requirements at Cassiar. The feasibility report was completed in October 1980.

d) A 7.5 MW variant utilizing some of the Site 1 features was studied in 1982 by Crippen (Desk Study).

e) A 12 MW development on the Cottonwood River was evaluated in 1983 by B.C. Hydro (Reconnaissance Study).

Of the above investigations, greatest confidence is placed in the 7.5 MW and 12 MW alternatives studied by Crippen. For both alternatives a storage dam is required and a common location of powerhouse is employed (approx Lat 59^{o} 7', long 130^{o} 10', NTS 104-0/1); the 7.5 MW project is based on a small storage dam whereas the 12 MW project is based on a larger storage dam downstram of the smaller damsite. Salient features of each project are as follows.

	Project		
	7.5 MW		12 MW
Dam Height (max)	15 m		30 m
Storage Volume	$40 \times 10^6 m^3$		$59 \times 10^6 m^3$
Gross Head	167 m		186
Maximum Flow	$6\ m^3/s$		$8\ m^3/s$
Annual energy	52×10^6 kWh	up to	85×10^6 kWh
Capital Cost (1980 $)	$30 860 000		$50 636 000
Construction Period	2.5 yrs.		3.5 yrs.

In each case a 48 km access road will be required from Cassiar as shown in Fig. 1.1. Details of the two alternatives are shown in Figs 3.1 and 3.2. If either of the above hydro schemes is developed, diesel generating capacity must be maintained at Cassiar to secure reliability of supply (in the event that the 48 km transmission line fails) and to ensure that mine shovel load transients are adequately met. The smaller 7.5 MW project cannot meet all of the Cassiar region energy or capacity demand and therefore diesel generation is required to supplement hydroelectric generation. The larger 12 MW project can meet the region's energy demand but may require supplementary diesel generation to meet infrequent peak demands.

A review and update of the above hydro development costs was made for the purpose of this study. Based on a comparison of current bidding conditions against 1980 cost levels a 15% increase in 1980 costs is considered appropriate to bring hydro project costs to 1984 levels. The estimated construction periods will be 3.5 years for the 12 MW project and 2.5 years for the 7.5 MW project. The difference in construction periods is due to the more complex and larger damsite for the 12 MW project. Tables 3.1 and 3.2 show capital and operating cost streams for each of the two hydroelectric alternatives.

While the 12 MW alternative was investigated to detailed feasibility study level, the 7.5 MW alternative was based on a subsequent office study. If the 7.5 MW project is implemented first, it will be possible to extend hydro resource development in the future by staged expansion in order to increase generating capacity. The upstream damsite can be abandoned in favour of second stage construction of the larger dam at the downstream damsite together with installation of additional turbine and generator units. Alternatively, it may be economic to develop damsites lower down on the Cottonwood utilizing the regulated discharge from the stage I powerhouse. Staged expansion alternatives have not been examined but it would appear economic to stage development at the site from 7.5 MW to 12 MW or more to meet future load growth. As much as 8 MW peak demand and 33 GW.h per year, typical of a 1400 tonnes per day mine and mill operation, could be accommodated with an incremental unit energy generating cost similar to the first stage project energy generating cost.

Various larger scale hydroelectric projects in the wider (Northcentral B.C.) region have been identified. These are discussed in Section 3.3.

3.2 Alternate Energy Sources

The most recent comprehensive review of alternate energy sources for the wider (Northcentral B.C.) region was carried out by B.C. Hydro Corporate Group for the Provincial Government Ministries of Industry and Small Business Development, and Energy, Mines and Petroleum Resources in 1983. The study examined the following four power supply options:

a) extensions from B.C. Hydro's grid;

b) energy supply from coal-fired thermal plant at Klappan;

c) hydro generation near mine sites, including small hydroelectric generation where identified;

d) diesel generation at mine sites.

The report concluded that there is no single preferred power option for all minesites at present. Insofar as Cassiar is concerned, the cost of extending transmission lines from the existing B.C. Hydro grid to areas North of Dease Lake exceeds the cost of local generation. B.C. Hydro concluded that diesel generation is the least cost power option for Cassiar. The report states that after implementation of the Iskut/Stikine project, transmission from this project would likely be the least cost power option. Based on the findings of the report, the alternate power supply options are limited:

a) Transmission lines from the South (B.C. Hydro and Power Authority) will be uneconomic until the Stikine/Iskut Development is implemented;

b) Thermal power sources are uneconomic;

c) The small hydro site on the Cottonwood examined by B.C. Hydro appears to be uneconomic.

Besides a connection between Cassiar and the B.C. Hydro grid, there is the long term possibility of connection to the Northern Canada Power Commission (NCPC) grid. In 1980 NCPC carried out a feasibility study of the False Canyon hydro site on the Francis River approximately 50 km north of Watson Lake, Yukon. The project envisaged an installed capacity of approximately 60 MW, with connections to the Whitehorse grid by transmission line down the Pelley River Valley. If this project were developed, NCPC would also service Watson Lake. A transmission line could be constructed from the False Canyon site via Watson Lake to Cassiar, a distance of approximately 160 km. An order of magnitude cost for such a transmission line with stepdown facilities would be $20,000,000. Current NCPC capacity and energy charges for 12 MW peak demand and 60 GW.h/year energy demand would be approximately $435,700/year and 0.961 cents per kW.h respectively.

The NCPC annual report of 1983 states that False Canyon is a viable project if high utilization factors can be attained. However, it is not known where this project ranks when compared to other Yukon hydroelectric development alternatives. Smaller projects (35 to 40 MW capacity) at Hoole Canyon site on the Pelley River and Ross Canyon on the Ross River, were also stated to be viable. NCPC therefore appear to have the flexibility to develop sizeable blocks of power geographically convenient to potential demand increases. Furthermore since the Cyprus Anvil mine closure in 1983, NCPC has a capacity surplus of 20 MW with the result that no further capacity increases are contemplated until either Cyrus Anvil resumes production or other major loads develop in the Yukon. False Canyon will therefore not likely be developed unless a major demand is established in the Southeast part of the Yukon. The timing of such a scenario is most likely consequent on future mining development.

Other alternative energy sources which have been considered for Cassiar are woodwaste, natural gas and nuclear sources. These are discussed briefly below.

TABLE 3.1 - PART I

REGIONAL UTILITY WITH 7.5 MW HYDRO PROJECT IMPLEMENTATION JULY 1987

Year	Demand[1]			Fuel & Lubricants[2]			
	Hydro GW.h	Diesel GW.h	Total GW.h	Diesel $Lx10^6$	Lube Oil $Lx10^6$	Diesel $x1 000	Lube Oil $x1 000
1984	-	59.13	59.13	17.15	.176	6 174	255
1985	-	59.13	59.13	17.15	.176	6 174	255
1986	-	59.13	59.13	17.15	.176	6 174	255
1987	26	31.93	57.93	9.12 + 0.7	.088	3 731	128
1988	52.1	5.83	57.93	1.66 + 1.3	.027	1 115	39
1989	▲	▲	▲	▲	▲	▼	▲
1990							
1991						increasing	
1992						to	
1993							
1994						▼	▼
1995						1 142	39
1996							▲
1997							
1998							
1999						▼	
2000						increasing	
2001						to	
2002							
2003							
2004						▼	▼
2005	52.1	5.83	57.93	1.66 + 1.3	.027	1 219	39

(1) 7.5 MW hydro can supply 52.1 GW.h/year.

(2) Diesel fuel quantities after 1987 includes purchase of heating fuel to replace waste heat recovery foregone.

TABLE 3.1 - PART 2

REGIONAL UTILITY WITH 7.5 MW HYDRO PROJECT IMPLEMENTATION JULY 1987

($ x 1 000)

Year	Capital Costs[1]	Operating Costs $[2] (excl.diesel,lube oil)		Maintenance Costs		Salvage
		Hydro	Diesel	Hydro	Diesel	Existing Diesel
1984	-	-	700	-	1 150	-
1985	4 000	-	700	-	1 150	-
1986	20 000	-	700	-	1 150	-
1987	14 900	80	400	-	400	-100
1988	-	200	70	125	150	-
1989	-	▲	▲	▲	▲	-
1990	-	|	|	|	|	-
1991	-	|	|	|	|	-
1992	-	|	|	|	|	-
1993	-	|	|	|	|	-
1994	-	|	|	|	|	-
1995	-	|	|	|	|	-
1996	-	|	|	|	|	-
1997	-	|	|	|	|	-
1998	-	|	|	|	|	-
1999	-	|	|	|	|	-
2000	-	|	|	|	|	-
2001	-	|	|	|	|	-
2002	-	|	|	|	|	-
2003	-	|	|	|	|	-
2004	-	|	|	|	|	-
2005	-	200	70	125	150	-

(1) Total capital cost based on 1980 dollar cost of $31 million plus 15% escalation plus cost of transmission lines to other customers. Total 39.9 million.

(2) Hydro operating costs based on 5 dedicated staff plus transportation.

NOTES

- Environmental impact study and mitigation costs not included.
- Water rights costs (approx 0.5 c/kW.h) not included.
- Generation at Erickson, Taurus & D.O.H. assumed autonomous until hydro on line July 1987.

TABLE 3.2 - PART I

REGIONAL UTILITY WITH 12 MW HYDRO PROJECT IMPLEMENTATION JULY 1988

Year	Demand (1)			Fuel & Lubricants (2)			
	Hydro GW.h	Diesel GW.h	Total GW.h	Diesel $L \times 10^6$	Lube Oil $L \times 10^6$	Diesel $\$ \times 1\,000$	Lube Oil $\$ \times 1\,000$
1984	-	59.13	59.13	17.15	.176	6 174	255
1985	-	59.13	59.13	17.15	.176	6 174	255
1986	-	59.13	59.13	17.15	.176	6 174	255
1987	-	57.93	57.93	16.55	.173	6 289	250
1988	27.46	30.47	57.93	8.7 + 0.75	.088	3 562	127
1989	54.93	3	57.93	0.85 + 1.49	.014	882	20
1990	▲	▲	▲	▲	▲	▼	▲
1991							
1992						increasing	
1993						to	
1994						▼	
1995						903	
1996							
1997							
1998						▼	
1999						increasing	
2000						to	
2001							
2002							
2003							
2004						▼	
2005	54.93	3	57.93	0.85 + 1.49	.014	964	20

(1) 12 MW Hydro can supply 58 GW.h/year.

(2) Diesel fuel quantities after 1988 includes purchase of heating fuel to replace waste heat recovery foregone.

TABLE 3.2 - PART 2

REGIONAL UTILITY WITH 12 MW HYDRO PROJECT IMPLEMENTATION JULY 1988

($ x 1 000)

Year	Capital Costs[1]	Operating Costs $[2] (excl.diesel,lube oil)		Maintenance Costs		Salvage
		Hydro	Diesel	Hydro	Diesel	Existing Diesel
1984	-	-	700	-	1 150	-
1985	4,000	-	700	-	1 150	-
1986	20,000	-	700	-	1 150	-
1987	30,000	-	700	-	1 150	-
1988	7,500	100	400	-	400	-500
1989	-	200	50	175	100	-
1990	-	▲	▲	▲	▲	-
1991	-					-
1992	-					-
1993	-					-
1994	-					-
1995	-					-
1996	-					-
1997	-					-
1998	-					-
1999	-					-
2000	-					-
2001	-					-
2002	-					-
2003	-					-
2004	-	▼	▼	▼	▼	-
2005	-	200	50	175	100	-

(1) Total Capital Cost based on 1980 dollar cost of $ 50.63 million plus 15% escalation plus cost of transmission lines to other customers. Total $61.5 million.

(2) Hydro operating costs based on 5 dedicated staff plus transportation.

NOTES

- Environmental Impact Study and Mitigation Costs Not Included
- Water Rights Costs (Approx 0.5 c/kW.h) Not Included
- Generation at Erickson, Taurus, D.O.H. assumed autonomous until hydro on line July 1988

a) Woodwaste

The quantity of woodwaste available in the area is small in relation to the energy needs at Cassiar.

b) Natural Gas

In 1982 a rough estimate of the cost of installation of a 75 mm (3 inch) gas pipeline 690 km from Fort Nelson was made by Brinco. This amounted to $64 million. It was further estimated that the maximum savings based on then current gas prices would be $6 million annually. More accurate costs will be required before this alternative can be seriously considered, however it appears that the payback period would be too long for private enterprise development.

c) Nuclear

Interest has been expressed in the commercial development of the "Slow Poke" reactor. This reactor is currently being developed by the Atomic Energy Commission for heat generation, not for electrical generation. If the reactor does become available commercially, it might be considered for displacement of heating fuel at Cassiar.

Based on the above, it appears that the only viable short-term energy sources for Cassiar are diesel generation or combined diesel/hydroelectric using a local small hydroelectric source. This situation will change when the B.C. Hydro Iskut/Stikine development proceeds, or it may change if a large new mining property is developed and Cassiar can take advantage of economics of scale associated with power supply to other consumers.

3.3 Energy Conservation

Operations at Cassiar have an active ongoing energy conservation program. In August 1980, an energy audit of plant, office and residential facilities was jointly undertaken by Brinco and the B.C. Energy Commission. The review identified areas where insulation and/or waste heat recovery improvement can be made and these have been included in the ongoing improvements program. Brinco's energy management group constantly review mining and mill activities for potential energy conservation improvements. The criteria for investment in Capital improvements is a maximum of a two year payback period unless other advantages occur.

3.4 Social Benefit-Cost Analysis of Small Hydro

The preferred small hydro development alternatives should be assessed within the context of a social benefit-cost analysis framework to determine which alternative, if any, best satisfies the broad social interests of Canada and/or the Province of British Columbia.

The Federal and Provincial governments both have published guidelines on social benefit-cost analysis to assist in determining the overall desirability of potential projects.(1)

The social benefits and costs of small hydro development are identified in Table 3.3. The principal social benefit will be the foregone cost of existing diesel power systems, including the value of displaced diesel fuel and lubricants. Other social benefits may arise, including the value - added to the economy of extended mining production made possible soley because of lower-cost energy with small hydro.

Social costs would include the capital, operating and maintenance expenditures of the new small hydro power system, including the cost of using the existing diesel plant for peaking purposes. The costs of the new power system would also include transmission and distribution links to the targeted industrial, commercial and residential customers.

Small hydro development may have some impacts (positive and negative) on the people living in the region and on the physical environment. Such impacts (referred to in benefit-cost analysis as "externalities") would be included in the benefit-cost analysis to the extent that they reflect real changes in production or consumptive opportunities in the region.

TABLE 3.3

BENEFITS AND COSTS OF SMALL HYDRO DEVELOPMENT

Social Benefits	Social Costs
Displaced Energy	Costs of Small Hydro Power System
- Diesel Fuel	- Capital
- Lubricants	- Annual O & M
Avoided Costs of Existing Diesel Power System	Socio-Economic, Environmental & Others
- Capital	
- Annual O & M	
Other Energy Cost Savings	
Extended Mining Activity	
Socio-Economic, Environmental & Other	

1) Treasury Board, Government of Canada, Benefit-Cost Analysis Guide, Ottawa, 1976;
Environment and Land Use Secretariat, Province of British Columbia, Guidelines for Benefit-Cost Analysis, Victoria, 1977.

The social benefit-cost analysis of small hydro development would employ assumptions similar to the following:

i) Incremental Analysis:

Small hydro alternatives would be assessed incrementally to the existing system, therein addressing the question as to whether society would be better off "with" or "without" the development.

ii) Referent Group:

The analysis could be undertaken from the perspective of Canada and/or the Province of British Columbia. In addition, the analysis could be disaggregated to the extent of identifying the impacts on the private and government sectors.

iii) Valuation Principles:

Social benefits and costs are valued on the basis of highest alternative use (ie; social opportunity cost). For some impacts in which market prices either do not exist or do not reflect the social opportunity cost, it may be necessary to impute values (ie; "shadow pricing").

iv) Social Discount Rate:

The discount rate should reflect the social opportunity cost of capital.

v) Inflation:

Benefit-cost analysis typically projects benefits and costs assuming constant dollars therein avoiding the complexity of forecasting inflation rates.

vi) Sensitivity Analysis:

It is important to determine the impact on net benefits from changes in key assumptions. Sensivitivity testing for energy projects typically includes the discount rate, capital costs and projected energy prices.

vii) Evaluation Period:

The economic life of mining production with small hydro should determine the evaluation period.

viii) Evaluation Criteria:

These typically include net social benefits, benefit-cost ratio and internal rate-of-return.

Preliminary analysis of benefits and costs has been undertaken for the 7.5 MW and 12 MW small hydro development cases for illustrative purposes. Each case was assessed incrementally to the "without" small hydro case.

The social benefits identified in the preliminary analysis include the value of displaced petroleum products (diesel fuel, lubricants) and the avoided costs (capital, operating and maintenance) of existing diesel operations. The social

costs include the capital costs for small hydro development (including transmission and distribution) and annual operating and maintenance costs, including water rental fees.

The time frame for the preliminary analysis was 1984 to 2005. While it is recognized that the small hydro development could likely extend the period for economic mineral production, the analysis adopts a conservative approach and excludes this potential benefit.

Benefits and costs in the analysis are expressed in 1984 constant dollars. A base social discount rate of eight percent is used in the analysis with sensitivity testing using five percent and ten percent. These are real, pre-tax rates.

The principal assumptions developed for the analysis are presented in Table 3.4.

TABLE 3.4

BENEFIT COST ASSUMPTIONS FOR SMALL HYDRO PROJECT FOR THE CASSIAR MINE

	7.5 MW Case	12 MW Case
Annual Volume Displaced Energy 1989-2005		
Diesel Fuel (000 litres)	13 300	13 920
Lubricants (000 litres)	146	159
Avoided Costs of Existing Diesel System ($000)		
Capital Costs, one unit in 1985 and one in 1995	$ 9,000	$ 9,000
Annual O & M (full operation)	$ 1,255	$ 1,325
Incremental Costs of Small Hydro Development ($000)		
Capital Costs	$ 38,900	$ 61,500
Annual O & M (full operation)	$ 450	$ 520

The 7.5 MW case assumes annual displacement of 13.3 million litres of diesel fuel while the 12 MW case would annually displace 13.9 million litres under full operation. The value of displaced diesel fuel is determined by applying the price forecast presented in Table 2.1. For example, the value of displaced diesel fuel in 2005 is $5.5 million for the 7.5 MW case and $5.7 million for the 12 MW case.

---

1) Costs for existing and small hydro facilities reflect real resource costs. Items such as depreciation and interest are not real resource costs and are excluded from the analysis.

In the absence of a new energy supply system, the existing diesel power system would require capital expenditures of $9 million for the purposes of maintaining mineral production to the year 2005. Annual operating and maintenance expenditures for the existing system are estimated in the order of $1.3 million.

The 7.5 MW case could entail capital costs of approximately $40 million and a three year construction period with full operations commencing in 1988. The 12 MW case could entail capital costs of about $62 million and a four year construction period with full operations commencing in 1989. Operating and maintenance expenditures for the 7.5 MW case are some ten to fifteen percent less than for the 12 MW case.

The results of this preliminary analysis are presented in Table 3.5. The results indicate that the 7.5 MW case is considerably more efficient than the 12 MW case for the projected displaced load. Furthermore, the 7.5 MW case represents an efficient allocation of resources for society. The internal rate-of-return for the 7.5 MW case (seventeen percent) is well above the social opportunity cost of capital and the benefit-cost ratios for the 7.5 MW case exceed unity for the three discount rates employed in the analysis.

TABLE 3.5

PRELIMINARY SOCIAL BENEFIT-COST ANALYSIS OF SMALL HYDRO DEVELOPMENT FOR CASSIAR MINE

		7.5 MW CASE	12 MW CASE
I.	Project Internal Rate-of-Return (IRR)	17%	8%
II.	Net Benefits (1984 $Millions)		
	Discount Rate		
	8%	19	-
	5%	35	14
	10%	12	-5
II.	Benefit-Cost Ratio		
	Discount Rate		
	8%	1.6	1.0
	5%	1.9	1.2
	10%	1.4	.9

3.5 Socio-Economic & Environmental Impact Considerations For Small Hydro Development

3.5.1 Socio-Economic Impact Considerations

The proposed small hydro development may provide existing and prospective mines in the Cassiar region with a long term and reliable supply of low-cost

energy which could result in additional value-added in terms of mineral output. This additional value-added income represents: wages and salaries for the incremental person-years of employment; purchases of goods and services within the region, the province and the country; tax payments to all levels of government; corporate income which facilitates further reinvestment in mining; and other income.

The socio-economic impact of the proposed small hydro development has two distinct facets. First, it facilitates continuance of the positive socio-economic impact from existing operations. Second, there will be positive socio-economic stimulus to the region in terms of the small hydro construction phase and in terms of facilitating mining activity which would not have occurred without the development.

The existing socio-economic conditions in the region are described herein and the potential socio-economic impact from small hydro development will be assessed as the project becomes more specifically defined. A brief temporal overview (past. present and future) of mining in the Cassiar region is provided prior to the presentation of existing socio-economic conditions.

3.5.2 Mining Developments

Brinco Mining Limited owns and operates the Cassiar Asbestos mine in Northwest B.C. Construction of the mine was initiated in 1951 by Cassiar Asbestos Corporation Limited, and production commended in 1953. Brinco purchased the mine in 1980-81, and now provides the most fully developed community services in the northwest to its work force and to others in the area. Costs of these services are high, due to the remote location of the mine, and to the limited availability of publically funded infrastructure which is commonly available to residents of the rest of the province.

The Cassiar mine is an open pit asbestos mine with a production capacity exceeding 100 000 tonnes per year of high-grade chrysotile asbestos fibre, mainly in the asbestos cement grades. It is located in Northwest British Columbia just south of the Yukon border.

In 1983, prices of Cassiar's product ranged from $500 up to $2,000 per tonne. By comparison, the price for Quebec asbestos was $440 per tonne. While Cassiar's weighted average price is approximately twice that of Quebec asbestos, the premium reflects the relatively high grade of Cassiar's product.

The market for asbestos has been influenced by the controversy regarding health effects of asbestos usage. To date, however, no substitute which is both cost competitive and equal in performance has been found. Those that can in part replace asbestos show signs of having similar properties vis a vis health and environment. Emerging markets in less developed countries (where costs concerns outweigh possible environmental and health impacts of asbestos use) are expected to more than offset declining demand in traditional markets.

The existing Cassiar open pit reserves will be fully exploited by mid 1990. Future prospects are promising, however, as Brinco has defined another major ore body (the McDame deposit), has explored the feasibility of extraction of additional (lower grade) asbestos from the tailing pile, and is continuing to explore and evaluate other deposits in the area.

Exploitation of these additional reserves will depend on international market demand for asbestos and costs of the delivered product. In this latter connection, a long term supply of low-cost electric energy could extend economic mining production at least another decade (to 2005) and possibly well beyond that date.

Other mineral deposits in the Cassiar area could improve their viability with a long term supply of low-cost electric energy. Two operating mines in the Cassiar area - Erickson Gold Mine and Hearne Taurus Mine - could likely be integrated into the proposed small hydro utility operation. In addition to these two operating mines, ten other significant deposits with mine potential have been located in the vicinity of Cassiar.

3.5.3 Existing Socio-Economic Conditions

The employment impact of the Cassiar and other adjacent mines is significant to the northwest region of B.C., the province and Canada. As indicated in Table 3.6 below, these mines generated nearly 1600 jobs in Canada in 1983, including the indirect and induced ("multiplier") effects. Within British Columbia, some 925 jobs were generated by these mines of which about 760 were located in the northwest region.

TABLE 3.6

SUMMARY OF
1983 DIRECT EMPLOYMENT
AND
ESTIMATED INDIRECT AND INDUCED EMPLOYMENT

Location	Direct Cassiar Mine	Direct Other Mines	Indirect	Induced	TOTAL
Cassiar	410	120	30	160	720
Stewart	-	-	30	10	40
Other B.C.	65	-	100	-	165
Rest of Canada or Unknown	-	-	105	545	650
TOTAL	475	120	265	715	1575

Indirect and induced employment refers to jobs generated by both the Cassiar operation and the two smaller mines in the area. Some Brinco employees providing retail and municipal services are included in the induced column.

All values are rounded to the nearest 5.

The labour income (wages, salaries and benefits) attendant to this employment impact was about $50 million in Canada in 1983 as shown in Table 3.7. The labour income was $32 million and $25 million respectively for British Columbia and the northwest region.

TABLE 3.7

ESTIMATED 1983 DIRECT, INDIRECT AND INDUCED LABOUR INCOME (millions of 1983 dollars)

Location	Direct Cassiar Mine	Direct Other Mines	Indirect	Induced	TOTAL
Cassiar	15.3	4.5	1.0	4.3	25.1
Other B.C.	2.5	-	4.4	-	6.9
Rest of Canada or Unknown	-	-	3.5	14.5	18.0
TOTAL	17.8	4.5	8.9	18.8	50.0

Direct purchases by the Brinco Cassiar mine in 1983 were about $21 million. Some $13.5 million of this amount related to purchases within British Columbia. The most significant direct purchases in 1983 were for fuel and lubricants ($7 million) and equipment ($4 million).

Brinco pays significant amounts to governments in respect of taxes for its Cassiar Mine. Some $7 million was paid in 1983 in terms of payments on behalf of employees for income taxes, Worker's Compensation, Canada Pension Plan and Unemployment Insurance. In addition, Brinco and others in Cassiar paid over $6 million to British Columbia in 1983 in respect of corporate income taxes, property taxes, sales and excise taxes, capital taxes, but excluding mining taxes.

3.5.4 Environmental Impact Considerations

An environmental impact assessment of the proposed small hydro development would be undertaken to ensure protection of the environment. A brief outline of a possible environmental impact study program is as follows:

i) Water Quality

The program would collect and assess existing information, and collect additional site specific information to document baseline conditions. The impact assessment would address changes in water levels, nitrogen supersaturation and effects of construction activities. Recommendations would be made to mitigate and manage potential impacts.

ii) Fisheries

The present fisheries values in the Cottonwood River are not considered to be high. There are no salmon, but Dolly Varden and Arctic grayling do occur. The fisheries resources would need to assess both habitat capability, species present and populations. An assessment would be made on the effects of changing flows downstream, construction impacts, the location of discharge and change of flow regime effects on spawning and rearing, water quality, fish migration, and so forth.

iii) Wildlife

Construction of the powerline, roads, reservoir and powerhouse will impact wildlife in the area. Studies are required to document wildlife values, potential effects and mitigation measures resulting from direct and indirect impacts such as from increased road access. Moose and Grizzly Bear will be the main species of concern.

iv) Resource Use

Resource use would consider land capabilities for uses such as forestry, hunting, fishing and trapping, and any potential effects on settlements. Methods for managing impacts would be recommended.

v) Reclamation/Environmental Management

Reclamation planning and environmental impact management procedures would need to be developed for environmental protection. Reclamation plans would consider plant communities and site factors, natural re-vegetation together with engineering plans.

A combined environmental management plan should be developed to provide for reclamation and environmental protection during construction of the project.

4. PROPOSAL FOR A REGIONAL SMALL HYDRO UTILITY

4.1 Corporate Structure and Financing Alternatives

The optimal financing method for this specific project will be ascertained without detailed information of Brinco's financial position at the time a decision is made to proceed with this project. The investment dealer contacted had numerous questions as to Brinco's financial status and the Cassiar Mine financial situation and projected operating life. These questions plus other investigations would have to be addressed by way of an assignment to an investment dealer before a specific financing method could be recommended.

In order to provide guidance in assessing the feasibility of the project a number of scenarios have been assumed in the financial analysis. The financial analyses have been done on the basis of a newly incorporated separate utility company financed through traditional utility financing methods. Other organizational structures are discussed with the financial advantages of these structures coming from the income tax benefits that may be achieved. However, identification of the specific benefits cannot be measured without detailed information on Brinco's and other potential utility participants' income tax position.

Utility Company

Small regional utilities established in remote areas will frequently, if not always, depend on a single industry. The utility demand will probably depend on the requirements of a single major industrial load and an attendant community. As a result, the economic underpinning of the utility service area is the starting point in assessing the financial risk in establishing any small regional utility. If reasonable load stability can be assured in remote regions over a fifteen to twenty year period, it is expected that a utility could be financed with a fifty percent debt/equity ratio. At present, the cost of debt would likely be about fifteen percent with an additional four percent to five percent being required as a return on common equity. These financial assumptions are one area in which the separate utility may differ significantly from other alternatives, and present an appropriate area for future sensitivity analysis.

Another area in which differences may arise is the relative income tax position of the separate utility. At this time it appears that a separate utility would be eligible for the asset write-offs of Class 34 of the Income Tax Regulations with respect to a hydro project, but would not be able to obtain the Investment Tax Credit available as an industrial incentive under the Income Tax Act.

Class 34 provides for a rapid write-off of investments in machinery and equipment which save energy or use renewable sources of energy. Assets purchased before 1985 and certified by the Ministry of Energy, Mines and Resources may be written off over three years (up to 25% in the first year, up to 50% in the second year, and the balance in any subsequent year) as opposed to a 6% to 20% rate on a declining balance basis.

Brinco Ownership or Limited Partnership

The benefit of either of these organizational structures would be to flow through the income tax advantages obtained from Class 34 and of obtaining the Investment Tax Credit.

In the case of Brinco ownership, the large losses in utility operations realized through the application of Class 34 and which are shown in the financial projections could be of substantial benefit to Brinco depending on its income tax position and its effective tax rate.

As an alternative, a Limited Partnership could be formed to carry on the utility operation. The partnership could be syndicated into units and sold to limited partners, which could include the utility customers. Brinco or a subsidiary, formed for the purpose, could be the general partner with responsibility for managment of the utility. The utility as a Limited Partnership could also seek a proportion of debt financing and in this manner develop some leverage in the project and flow the Class 34 income tax benefits through to the limited partners.

For certain types of investments and depending on the area of British Columbia, there is a ten percent investment tax credit available under the Income Tax Act. The Act appears to offer sufficient scope so that if Brinco or also possibly the Limited Partnership were to undertake the utility project, the investment may qualify. The credit that is obtained is a credit of ten percent of the amount of the hydro investment (i.e., in this case either ten percent of $38.9 million or $61.5 million). This ten percent credit can be applied to the income tax payable by the entity and for income tax purposes carried back two years or forward for seven years. The amount of the investment is reduced by the amount of the credit for ongoing depreciation purposes. Further advice would need to be obtained on the interpretation of the relevant sections of the Income Tax Act as well as discussion with Revenue Canada officials before it can be ascertained if this benefit would definitely be available.

4.2 Utility Cost of Service And Rate Analysis

The approach taken in estimating the implications of the utility financial structure was to construct the pro forma annual revenue requirement or cost of service of the utility. The total revenue requirement was then divided by the electrical load to arrive at an average rate. These calculations are typical of those performed by utilities to support rate applications to the British Columbia Utilities Commission (BCUC) and other regulatory bodies. The following sections outline briefly the methodology, assumptions and results of this analysis.

4.2.1 Scenarios

Three scenarios were analyzed. The first scenario was a base case in which the utility purchased and operated the existing and any future diesel generating units. The second case involved the construction of a 7.5 MW hydro facility which was used for baseload requirements while some existing diesel units were retained for peaking and backup purposes. The final scenario involved construction of a 12 MW hydro facility which could supply virtually

all requirements but still required retention of some existing diesel units for backup.

4.2.2 Inflation

Costs, both capital and operating, were escalated to current dollars (dollars of the day) using a six percent inflation rate. The rates which resulted from the analysis were then deflated to 1984 constant dollars using this same rate.

4.2.3 Evaluation Period

The Evaluation period was 1984-2005, reflecting a reasonable, but not overly optimistic, economic life for the Cassiar Mine.

4.2.4 Capital Costs

The capital costs utilized were those identified by Crippen in their analysis of the required facilities. These costs include purchase of the existing diesel facilities for $1.2 million, and are assumed to include the right to operate the diesels at their existing locations. They are summarized below for each of the three scenarios.

Capital Costs
1984 $ x 1000

	Diesel	7.5 MW Hydro	12 MW Hydro
1984	1 200	1 200	1 200
1985	3 900	4 000	4 000
1986	0	20 000	20 000
1987	0	14 900	30 000
1988	0	0	7 500
1995	5 100	0	0

4.2.5 Operating and Maintenance Costs

The operating and maintenance costs utilized were also taken from estimates prepared by Crippen. They are summarized below:

Operating and Maintenance Costs
1984 $ x 1000

	Diesel	7.5 MW Hydro	12 MW Hydro
1984	1 850	1 850	1 850
1985	1 850	1 850	1 850
1986	1 475	1 850	1 850
1987	1 475	880	1 850
1988	1 475	545	900
1989-2005	1 475	545	525

---

1) This inflation assumption is consistent with that used by the BCUC in its recent financial analysis of the Vancouver Island Natural Gas Pipeline Project.

4.2.6 Diesel and Lube Oil Costs

Diesel and lube oil costs were projected by multiplying the required volumes, as supplied by Crippen, by the forecast delivered unit costs. Lube oil unit costs were assumed to remain constant at $1.45 per litre (1984 $) while diesel unit costs increased from $0.371 per litre to $0.412 per litre (1984 $) over the study period as in the previously described price forecast. Diesel volumes included only those required for electricity generation as it was expected that any makeup fuel required in the hydro scenarios to compensate for the reduction in waste heat recovery would not be the responsibility of the utility. The required volumes are summarized below:

Diesel and Lube Oil Volumes
(millions litres)

	Diesel		7.5 MW Hydro		12 MW Hydro	
	Diesel	Lube	Diesel	Lube	Diesel	Lube
1984	17.15	0.176	17.15	0.176	17.15	0.176
1985	17.15	0.176	17.15	0.176	17.15	0.176
1986	16.60	0.176	17.15	0.176	17.15	0.176
1987	16.26	0.173	9.12	0.088	16.55	0.173
1988	16.26	0.173	1.66	0.027	8.70	0.088
1989-2005	16.26	0.173	1.66	0.027	0.85	0.014

4.2.7 Water Licence Fees

Water licence fees are a provincial tax on the use of water in British Columbia. They are currently estimated, based on the Water Act, to be $2.85 per licenced MW and $2.00 per MW.h generated for a small hydro project. Future increases in excess of the rate of inflation are somewhat speculative since these charges are indexed to the increases in B.C. Hydro's average revenue per kWh of sales. Thus, policy changes regarding B.C. Hydro's interest coverage ratio. and fluctuations in domestic and export electricity sales can, among other factors, result in substantial variations in water licence fees. For the purposes of this analysis, modest real growth rate of 0.1% has been assumed.

4.2.8 Property Taxes

This preliminary analysis included an allowance for property taxes based on information provided by Lane Appraisals Limited (the firm currently advising Brinco on property tax matters at Cassiar). This information indicates that the effective property tax rates would be approximately 2.1%, 1.9% and 1.7% of the capital expenditures in the diesel, 7.5 MW hydro, and 12 MW hydro cases respectively. In addition, the current property tax on the existing diesel facilities is $75,000 (1984$).

4.2.9 Capital Structure and Cost of Funds

Based on discussions with financial market participants, it was deemed appropriate to assume a capital structure comprised of 50% equity and 50%

debt. The cost of debt at this time for an undertaking of a project of this nature is estimated to be 15% per annum. Discussions with the BCUC indicate that the allowed return on equity would be approximately 19%. These ratios and rates were assumed to apply over the life of the project.

4.2.10 Depreciation

Straight line depreciation of assets was utilized, and depreciation rates were assumed to be linked to the economic life of the equipment. Thus, diesel units, when in use as primary generation, were depreciated at 10% per annum (i.e., a ten year economic life), and at 5% when in use as peaking or backup units. Hydro facilities were depreciated at 5% (i.e., a twenty year economic life).

4.2.11 Income Taxes

A representative corporate income tax rate of 50% was assumed. Capital cost allowances (CCA's) for the diesel equipment, based on discussions with Revenue Canada, were calculated as 6% of the undepreciated capital cost. CCA's for the hydro projects were assumed to be those available under the accelerated write-off provisions of Class 34 - up to 25% in the first year, up to 50% in the second year, and the remainder in any succeeding year. Losses were carried forward and back to minimize income taxes payable. No allowance was made for investment tax credits since their applicability in the utility context remains questionable at this time.

4.2.12 Waste Heat Recovery

Waste heat from the diesel exhaust can be recovered and used in Brinco's mining operations. In order to put the various options on an equal basis, it was assumed that this heat could be sold to Brinco by the utility. The value, based on discussions with Crippen, was put at 10% of the fuel consumed in diesel generation.

4.2.13 Revenue Requirement

The first step in calculation of the revenue requirement is determination of the mid-year rate base. The most significant portion of this is the mid-year net plant in service which is equal to the average of the first of year (FOY) and end of year (EOY) net plant (net plant is equal to the sum of all additions less accumulated depreciation and retirements). Additions are brought into the rate base in the year in which they first enter service, and are calculated by inflating the capital costs in constant dollars to current dollars and adding interest during construction at the utilities weighted average cost of capital of 17% per annum.

The other component of the rate base is working capital which is required to accommodate the normal forty-five day delay between expenses and collections. It is calculated by taking 12.5% of the cash portion of annual revenue requirements.

The rate base is the sum of the mid-year net plant in service and working capital.

The next step requires calculation of the earned return which is the sum of the return on debit and equity. These are calculated by multiplying the appropriate share of capital and rate of return by the mid-year rate base.

Expenses are determined by summing operating and maintenance, property tax, depreciation, diesel fuel, water licence fees and lube oil expenses.

Finally, income taxes are calculated by combining the return on equity, the tax rate, timing differences between CCA's and depreciation, any previous losses applied to reduce current taxable income and any current losses carried back to the previous taxation year.

Since required revenue is equal to earned return plus expenses plus income taxes, there is necessarily an interdependence between income taxes and required revenue. Thus their estimation requires simultaneous solution of two equations.

4.2.14 Electricity Rates

The average cost of electricity is determined by subtracting revenues generated through the sale of waste heat from the required revenue and then dividing by the load as provided by Crippen. This results in an average rate expressed in current dollars which are then expressed in constant 1984 dollars through the application of the appropriate deflator.

Finally, a levellized cost is calculated from the point of view of the consumer by dividing the net present value of electricity revenues by the net present value of electricity sales for the period 1984 to the year in question. This produces the levelized rate which a consumer would be willing to pay (at the specified discount rate over the period) instead of the fluctuating rate.

4.2.14 Results

The detailed calculations and results are presented in Tables 4.1 to 4.3 overleaf. The tables present the results for the diesel, 7.5 MW hydro and 12 MW hydro scenarios for the base case (i.e. for the assumptions as outlined in sections 4.2.1 to 4.2.13). Figure 4.1 shows the graph of unit energy costs against time. These results indicate that the 7.5 MW hydro alternative is preferable from a customer's point of view as it offers the lowest levellized rates for the period 1984-2005 at real discount rates of both 5 and 10 percent.

Table 4.4 presents a sensitivity analysis of some of the important assumptions of the analysis through calculation of the difference in levellized rates for the period 1984-2005 under different sets of assumptions for the diesel and 7.5 MW hydro scenarios. Case 1 is the base case as presented in Table 4.1 while Cases 2 through 5 were derived by varying the base case with respect to the level of property taxes, the CCA's available, the cost of debt and equity, and the water licence fees payable respectively. As shown in Table 4.4, the effect of a decrease in property taxes, or reduced cost of debt and equity, or elimination of water licence fees increases the desirability of the 7.5 MW hydro alternative, whereas loss of the Class 34 CCA for the 7.5 MW hydro alternative eliminates its advantage over the diesel alternative.

4.3 Government Regulatory Requirements

The creation of a regional public utility company to develop, own and operate a small hydroelectric generating plant requires that consideration be given to two legislatively separate issues:

1) What constitutes a regional public utility and under what legislation could it be created and operated; and

2) What constitutes a small hydroelectric generating project and what permits and approvals are needed:

British Columbia's Utilities Commission Act interprets a "public utility" to be "... a person, or his lessee, trustee, receiver or liquidator, who owns or operates in the province, equipment or facilities for

(a) the production, generation, storage, transmission, sale, delivery or furnishing of electricity, gas, steam.....to or for the public or a corporation for compensation" (emphasis added).

Thus, any entity engaged in the production and sale of electricity for compensation is deemed under the Act to be a public utility. As such, it is subject to the provisions of Part 3 of the Act which deals with regulation of public utilities. Several clauses in this part of the Act could bear on whether or not the utility is subject to regulation by the Utilities Commission. Section 27, Part 3 deals with entities generating electricity for their own use. Specifically 27(2) and (3) state:

"(2) A person who produces a power service primarily for his own purposes shall not sell any part of the power service that is surplus to his requirements except where the person:

(a) is selling the power service to persons who are his employees or tenants.

(b) is a member of a class permitted to sell surplus power by order of the minister, or

(c) sells the surplus power service under and in accordance with an order made by:

(i) the minister on his own or after referring the matter to the commission for a review, or

(ii) the commission, where authorized by the minister."

(3) An order referred to in subsection 2(b) or (c) may exempt the person or member of the class selling the power service from provisons of Part 3 specified in the order,...." (emphasis added).

Thus, although the entity may be classed as a public utility, it may be exempted from the provisions of Part 3 by either the Minister or the Commission.

TABLE 4.1 - Part 1

COLUMBIA PACIFIC

Cassiar Small Hydro - Utility Revenue Requirement ($000)
Scenario:Diesel

Fiscal Year Beginning Jan 1	1984	1985	1986	1987	1988	1989	1990	1991	1992
Inflation Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Inflation Factor (1984=1)	1.0000	1.0600	1.1236	1.1910	1.2625	1.3382	1.4185	1.5036	1.5938
Plant:									
Gross-EOY:Hydro	0	0	0	0	0	0	0	0	0
Diesel	0	1200	5334	5334	5334	5334	5334	5334	5334
Net-EOY:Hydro	0	0	0	0	0	0	0	0	0
Diesel	0	1200	5214	4681	4147	3614	3080	2547	2014
Additions:Hydro	0	0	0	0	0	0	0	0	0
Diesel	1200	4134	0	0	0	0	0	0	0
Salvage:Diesel-Gross	0	0	0	0	0	0	0	0	0
-Net	0	0	0	0	0	0	0	0	0
Depreciation Rate:Hydro	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Diesel	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Depreciation:Hydro	0	0	0	0	0	0	0	0	0
Diesel	0	120	533	533	533	533	533	533	533
Net-EOY:Hydro	0	0	0	0	0	0	0	0	0
Diesel	1200	5214	4681	4147	3614	3080	2547	2014	1480
Net-Mid-year	600	3207	4947	4414	3881	3347	2814	2280	1747
Working Capital	559	1235	1327	1370	1436	1506	1584	1662	1751
Mid-year Rate Base	1159	4442	6275	5784	5316	4853	4398	3942	3498
Revenue Requirement:									
Debt	50%	@	15%						
Equity	50%	@	19%						
Cost of Debt	87	333	471	434	399	364	330	296	262
Return on Equity	110	422	596	549	505	461	418	374	332
Earned Return	197	755	1067	983	904	825	748	670	595
Expenses:									
O&M	925	1961	1657	1757	1862	1974	2092	2218	2351
Property Taxes	75	166	176	187	198	210	223	236	250
Depreciation	0	120	533	533	533	533	533	533	533
Diesel Generation:									
Unit Cost (c/l):									
Cost (1984$)	37.10	37.10	37.20	37.30	37.40	37.50	37.70	37.70	37.90
Cost (Current $)	37.10	39.33	41.80	44.42	47.22	50.18	53.48	56.69	60.41
Consumption (10E6 l)	8.58	17.15	16.60	16.26	16.26	16.26	16.26	16.26	16.26
Energy (% of load)	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Fuel	3181	6744	6938	7223	7677	8160	8696	9217	9822
Water Licence Fees:									
Unit Cost:									
Real Growth		0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Demand ($/kW)	2.85	3.02	3.21	3.40	3.61	3.83	4.07	4.32	4.58
Commodity ($/MWh)	2.00	2.12	2.25	2.39	2.54	2.69	2.85	3.03	3.21
Licenced Capacity (MW)	0	0	0	0	0	0	0	0	0
Fees	0	0	0	0	0	0	0	0	0

TABLE 4.1 - Part 1 (Continued)

16-Dec-84

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
1.6895	1.7908	1.8983	2.0122	2.1329	2.2609	2.3966	2.5404	2.6928	2.8543	3.0256	3.2071	3.3996
0	0	0	0	0	0	0	0	0	0	0	0	0
5334	5334	5334	9681	9681	9681	9681	9681	9681	9681	9681	9681	9681
0	0	0	0	0	0	0	0	0	0	0	0	0
1480	947	413	9681	8713	7745	6777	5809	4841	3873	2904	1936	968
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	9681	0	0	0	0	0	0	0	0	0	0
0	0	5334	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
0	0	0	0	0	0	0	0	0	0	0	0	0
533	533	413	968	968	968	968	968	968	968	968	968	968
0	0	0	0	0	0	0	0	0	0	0	0	0
947	413	9681	8713	7745	6777	5809	4841	3873	2904	1936	968	0
1214	680	5047	9197	8229	7261	6293	5325	4357	3388	2420	1452	484
1850	1952	2133	2429	2551	2685	2825	2979	3138	3315	3504	3699	3915
3063	2632	7181	11626	10780	9946	9118	8304	7495	6703	5924	5151	4399
230	197	539	872	808	746	684	623	562	503	444	386	330
291	250	682	1104	1024	945	866	789	712	637	563	489	418
521	447	1221	1976	1833	1691	1550	1412	1274	1140	1007	876	748
2492	2642	2800	2968	3146	3335	3535	3747	3972	4210	4463	4731	5014
265	281	501	531	563	597	633	671	711	754	799	847	897
533	533	413	968	968	968	968	968	968	968	968	968	968
38.20	38.40	38.60	38.90	-39.10	39.40	39.60	39.90	40.10	40.40	40.70	40.90	41.20
64.54	68.77	73.27	78.27	83.40	89.08	94.90	101.36	107.98	115.32	123.14	131.17	140.06
16.26	16.26	16.26	16.26	16.26	16.26	16.26	16.26	16.26	16.26	16.26	16.26	16.26
100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
10494	11182	11914	12727	13560	14484	15431	16481	17558	18750	20023	21329	22774
0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
4.86	5.16	5.47	5.80	6.16	6.53	6.93	7.36	7.81	8.28	8.79	9.32	9.89
3.41	3.62	3.84	4.07	4.32	4.59	4.87	5.16	5.48	5.81	6.17	6.54	6.94
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0

COLUMBIA PACIFIC

TABLE 4.1 - Part 2

Cassiar Small Hydro - Utility Revenue Requirement ($000)
Scenario:Diesel

Fiscal Year Beginning Jan 1	1984	1985	1986	1987	1988	1989	1990	1991	1992
Inflation Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Inflation Factor (1984=1)	1.0000	1.0600	1.1236	1.1910	1.2625	1.3382	1.4185	1.5036	1.5938
Lube Oil:									
Unit Cost ($/l):									
Cost (1984$)	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Cost (Current $)	1.45	1.54	1.63	1.73	1.83	1.94	2.06	2.18	2.31
Volume (kl)	88	176	176	173	173	173	173	173	173
Cost	128	271	287	299	317	336	356	377	400
Total Expenses	4309	9262	9592	9999	10588	11213	11900	12582	13356
Income Taxes:									
Tax Rate	50%	50%	50%	50%	50%	50%	50%	50%	50%
CCA Base:Hydro 25%	0	0	0	0	0	0	0	0	0
Hydro 50%	0	0	0	0	0	0	0	0	0
Hydro 25%	0	0	0	0	0	0	0	0	0
Diesel 6%	600	3231	5104	4798	4510	4239	3985	3746	3521
CCA:Hydro	0	0	0	0	0	0	0	0	0
Diesel	36	194	306	288	271	254	239	225	211
Accumul Losses	0	0	0	0	0	0	0	0	0
Applied Losses-Current	0	0	0	0	0	0	0	0	0
-Previous	0	0	0	0	0	0	0	0	0
Current Tax Loss	0	0	0	0	0	0	0	0	0
Income Taxes	74	348	823	795	768	740	712	683	654
Required Revenue	4580	10366	11482	11778	12259	12778	13359	13935	14605
Waste Heat Revenue:									
Diesel Recovery Factor	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Revenue	318	674	694	722	768	816	870	922	982
Load (GWh)	29.57	59.13	59.13	57.93	57.93	57.93	57.93	57.93	57.93
Elec Cost (mills/kWh)	144.2	163.9	182.5	190.8	198.4	206.5	215.6	224.6	235.2
(1984 mills/kWh)	144.2	154.6	162.4	160.2	157.1	154.3	152.0	149.4	147.5
Lev Elec Cost (1984 mills/kWh)									
5%	144.2	151.0	155.4	156.7	156.8	156.4	155.8	155.1	154.3
10%	144.2	150.9	155.1	156.4	156.5	156.2	155.7	155.1	154.5

TABLE 4.1 - Part 2 (Continued)

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
1.6895	1.7908	1.8983	2.0122	2.1329	2.2609	2.3966	2.5404	2.6928	2.8543	3.0256	3.2071	3.3996
1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
2.45	2.60	2.75	2.92	3.09	3.28	3.48	3.68	3.90	4.14	4.39	4.65	4.93
173	173	173	173	173	173	173	173	173	173	173	173	173
424	449	476	505	535	567	601	637	675	716	759	805	853
14208	15087	16105	17700	18773	19951	21168	22504	23884	25398	27011	28678	30507
50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
3310	3111	7765	12140	11412	10727	10083	9478	8910	8375	7873	7401	6956
0	0	0	0	0	0	0	0	0	0	0	0	0
199	187	466	728	685	644	605	569	535	503	472	444	417
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
626	597	630	1,344	1,308	1,269	1,229	1,188	1,146	1,102	1,057	1,011	969
15355	16131	17955	21020	21913	22912	23948	25104	26304	27640	29077	30588	32223
10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
1049	1118	1191	1273	1356	1448	1543	1648	1756	1875	2002	2133	2277
57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93
246.9	259.2	289.4	340.9	354.9	370.5	386.7	404.9	423.8	444.8	467.4	490.8	516.9
146.2	144.7	152.4	169.4	166.4	163.9	161.4	159.4	157.4	155.8	154.5	153.0	152.1
153.7	153.0	153.0	153.9	154.6	155.0	155.3	155.5	155.6	155.6	155.5	155.5	155.4
154.0	153.4	153.4	154.1	154.5	154.9	155.0	155.2	155.2	155.2	155.2	155.2	155.1

COLUMBIA PACIFIC

TABLE 4.2 - Part 1

Cassiar Small Hydro - Utility Revenue Requirement ($000)
Scenario:7.5 MW Hydro

Fiscal Year Beginning Jan 1	1984	1985	1986	1987	1988	1989	1990	1991	1992
Inflation Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Inflation Factor (1984=1)	1.0000	1.0600	1.1236	1.1910	1.2625	1.3382	1.4185	1.5036	1.5938
Plant:									
Gross-EOY:Hydro	0	0	0	0	49843	49843	49843	49843	49843
Diesel	0	1200	1200	1200	1200	1200	1200	1200	1200
Net-EOY:Hydro	0	0	0	0	49843	47350	44858	42366	39874
Diesel	0	1200	1080	960	840	780	720	660	600
Additions:Hydro	0	0	0	49843	0	0	0	0	0
Diesel	1200	0	0	0	0	0	0	0	0
Salvage:Diesel-Gross	0	0	0	0	0	0	0	0	0
-Net	0	0	0	0	0	0	0	0	0
Depreciation Rate:Hydro	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Diesel	10.00%	10.00%	10.00%	10.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Depreciation:Hydro	0	0	0	0	2492	2492	2492	2492	2492
Diesel	0	120	120	120	60	60	60	60	60
Net-EOY:Hydro	0	0	0	49843	47350	44858	42366	39874	37382
Diesel	1200	1080	960	840	780	720	660	600	540
Net-Mid-year	600	1140	1020	25821	49406	46854	44302	41750	39198
Working Capital	559	1162	1295	1047	969	966	964	963	964
Mid-year Rate Base	1159	2302	2315	26868	50376	47820	45266	42713	40162
Revenue Requirement:									
Debt	50%	@	15%						
Equity	50%	@	19%						
Cost of Debt	87	173	174	2015	3778	3587	3395	3203	3012
Return on Equity	110	219	220	2552	4786	4543	4300	4058	3815
Earned Return	197	391	394	4568	8564	8129	7695	7261	6827
Expenses:									
O&M	925	1961	2079	1048	688	729	773	819	869
Property Taxes	75	159	592	961	1019	1080	1145	1214	1287
Depreciation	0	120	120	120	2552	2552	2552	2552	2552
Diesel Generation:									
Unit Cost (c/l):									
Cost (1984$)	37.10	37.10	37.20	37.30	37.40	37.50	37.70	37.70	37.90
Cost (Current $)	37.10	39.33	41.80	44.42	47.22	50.18	53.48	56.69	60.41
Consumption (10E6 l)	8.58	17.15	17.15	9.12	1.66	1.66	1.66	1.66	1.66
Energy (% of load)	100.0%	100.0%	100.0%	55.1%	10.1%	10.1%	10.1%	10.1%	10.1%
Cost of Fuel	3181	6744	7168	4052	784	833	888	941	1003
Water Licence Fees:									
Unit Cost:									
Real Growth		0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Demand ($/kW)	2.85	3.02	3.21	3.40	3.61	3.83	4.07	4.32	4.58
Commodity ($/MWh)	2.00	2.12	2.25	2.39	2.54	2.69	2.85	3.03	3.21
Licenced Capacity (MW)	0	0	0	7.5	7.5	7.5	7.5	7.5	7.5
Fees	0	0	0	88	159	169	179	190	202

TABLE 4.2 - Part 1 (Continued)

18-Dec-8·

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
1.6895	1.7908	1.8983	2.0122	2.1329	2.2609	2.3966	2.5404	2.6928	2.8543	3.0256	3.2071	3.3996
49843	49843	49843	49843	49843	49843	49843	49843	49843	49843	49843	49843	49843
1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
37382	34890	32398	29906	27413	24921	22429	19937	17445	14953	12461	9969	7476
540	480	420	360	300	240	180	120	60	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
2492	2492	2492	2492	2492	2492	2492	2492	2492	2492	2492	2492	2492
60	60	60	60	60	60	60	60	60	0	0	0	0
34890	32398	29906	27413	24921	22429	19937	17445	14953	12461	9969	7476	4984
480	420	360	300	240	180	120	60	0	0	0	0	0
36646	34094	31542	28989	26437	23885	21333	18781	16229	13707	11215	8722	6230
967	1571	1692	1670	1649	1631	1614	1601	1589	1570	1566	1564	1567
37612	35665	33234	30659	28086	25516	22947	20382	17818	15277	12781	10287	7797
2821	2675	2493	2299	2106	1914	1721	1529	1336	1146	959	772	585
3573	3388	3157	2913	2668	2424	2180	1936	1693	1451	1214	977	741
6394	6063	5650	5212	4775	4338	3901	3465	3029	2597	2173	1749	1326
921	976	1035	1097	1162	1232	1306	1384	1468	1556	1649	1748	1853
1364	1446	1532	1624	1722	1825	1934	2051	2174	2304	2442	2589	2744
2552	2552	2552	2552	2552	2552	2552	2552	2552	2492	2492	2492	2492
38.20	38.40	38.60	38.90	39.10	39.40	39.60	39.90	40.10	40.40	40.70	40.90	41.20
64.54	68.77	73.27	78.27	83.40	89.08	94.90	101.36	107.98	115.32	123.14	131.17	140.06
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%	10.1%
1071	1142	1216	1299	1384	1479	1575	1683	1792	1914	2044	2177	2325
0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
4.86	5.16	5.47	5.80	6.16	6.53	6.93	7.36	7.81	8.28	8.79	9.32	9.89
3.41	3.62	3.84	4.07	4.32	4.59	4.87	5.16	5.48	5.81	6.17	6.54	6.94
7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
214	227	241	256	271	288	305	324	344	365	387	411	436

COLUMBIA PACIFIC

TABLE 4.2 - Part 2

Cassiar Small Hydro - Utility Revenue Requirement ($000)
Scenario:7.5 MW Hydro

Fiscal Year Beginning Jan 1	1984	1985	1986	1987	1988	1989	1990	1991	1992
Inflation Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Inflation Factor (1984=1)	1.0000	1.0600	1.1236	1.1910	1.2625	1.3382	1.4185	1.5036	1.5938
Lube Oil:									
Unit Cost ($/l):									
Cost (1984$)	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Cost (Current $)	1.45	1.54	1.63	1.73	1.83	1.94	2.06	2.18	2.31
Volume (kl)	88	176	176	88	27	27	27	27	27
Cost	128	271	287	152	49	52	56	59	62
Total Expenses	4309	9255	10246	6421	5252	5416	5593	5775	5974
Income Taxes:									
Tax Rate	50%	50%	50%	50%	50%	50%	50%	50%	50%
CCA Base:Hydro 25%	0	4240	22472	17746	0	0	0	0	0
Hydro 50%	0	0	4240	22472	17746	0	0	0	0
Hydro 25%	0	0	0	4240	22472	17746	0	0	0
Diesel 6%	600	1164	1094	1029	967	909	854	803	755
CCA:Hydro	0	1060	7738	16733	14491	4437	0	0	0
Diesel	36	70	66	62	58	55	51	48	45
Accumul Losses	0	0	717	8181	22303	29514	26910	20109	13547
Applied Losses-Current	0	0	0	0	0	2604	6801	6562	6322
-Previous	0	148	0	0	0	0	0	0	0
Current Tax Loss	0	865	7464	14122	7211	0	0	0	0
Income Taxes	74	(74)	0	0	0	0	0	0	0
Required Revenue	4580	9572	10639	10988	13815	13545	13288	13037	12802
Waste Heat Revenue:									
Diesel Recovery Factor	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Revenue	318	674	717	405	78	83	89	94	100
Load (GWh)	29.57	59.13	59.13	57.93	57.93	57.93	57.93	57.93	57.93
Elec Cost (mills/kWh)	144.2	150.5	167.8	182.7	237.1	232.4	227.8	223.4	219.3
(1984 mills/kWh)	144.2	142.0	149.3	153.4	187.8	173.7	160.6	148.6	137.6
Lev Elec Cost (1984 mills/kWh)									
5%	144.2	142.7	145.3	147.4	155.5	158.4	158.7	157.6	155.7
10%	144.2	142.7	145.2	147.2	154.7	157.4	157.8	156.9	155.4

TABLE 4.2 - Part 2 (Continued)

18-Dec-84

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
1.6895	1.7908	1.8983	2.0122	2.1329	2.2609	2.3966	2.5404	2.6928	2.8543	3.0256	3.2071	3.3996
1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
2.45	2.60	2.75	2.92	3.09	3.28	3.48	3.68	3.90	4.14	4.39	4.65	4.93
27	27	27	27	27	27	27	27	27	27	27	27	27
66	70	74	79	84	89	94	99	105	112	118	126	133
6188	6412	6651	6907	7175	7464	7767	8093	8435	8743	9133	9543	9983
50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
710	667	627	589	554	521	489	460	433	407	382	359	338
0	0	0	0	0	0	0	0	0	0	0	0	0
43	40	38	35	33	31	29	28	26	24	23	22	20
7225	1142	0	0	0	0	0	0	0	0	0	0	0
6083	1142	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	4,758	5,672	5,429	5,187	4,945	4,703	4,461	4,219	3,919	3,683	3,448	3,213
12582	17234	17972	17548	17137	16747	16371	16019	15683	15259	14989	14739	14521
10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
107	114	122	130	138	148	158	168	179	191	204	218	233
57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93
215.3	295.5	308.1	300.7	293.4	286.5	279.9	273.6	267.6	260.1	255.2	250.7	246.7
127.5	165.0	162.3	149.4	137.6	126.7	116.8	107.7	99.4	91.1	84.4	78.2	72.6
153.3	154.2	154.7	154.4	153.5	152.2	150.6	148.9	147.1	145.2	143.3	141.4	139.5
153.5	154.2	154.6	154.3	153.7	152.8	151.7	150.6	149.4	148.2	147.0	145.9	144.8

COLUMBIA PACIFIC

TABLE 4.3 - Part 1

Cassiar Small Hydro - Utility Revenue Requirement ($000)
Scenario:12 MW Hydro

Fiscal Year Beginning Jan 1	1984	1985	1986	1987	1988	1989	1990	1991	1992
Inflation Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Inflation Factor (1984=1)	1.0000	1.0600	1.1236	1.1910	1.2625	1.3382	1.4185	1.5036	1.5938
Plant:									
Gross-EOY:Hydro	0	0	0	0	0	88826	88826	88826	88826
Diesel	0	1200	1200	1200	1200	1200	1200	1200	1200
Net-EOY:Hydro	0	0	0	0	0	88826	84385	79943	75502
Diesel	0	1200	1080	960	840	720	660	600	540
Additions:Hydro	0	0	0	0	88826	0	0	0	0
Diesel	1200	0	0	0	0	0	0	0	0
Salvage:Diesel-Gross	0	0	0	0	0	0	0	0	0
-Net	0	0	0	0	0	0	0	0	0
Depreciation Rate:Hydro	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Diesel	10.00%	10.00%	10.00%	10.00%	10.00%	5.00%	5.00%	5.00%	5.00%
Depreciation:Hydro	0	0	0	0	0	4441	4441	4441	4441
Diesel	0	120	120	120	120	60	60	60	60
Net-EOY:Hydro	0	0	0	0	88826	84385	79943	75502	71061
Diesel	1200	1080	960	840	720	660	600	540	480
Net-Mid-year	600	1140	1020	900	45193	87295	82794	78293	73791
Working Capital	559	1161	1287	1398	1292	1469	1448	1428	1410
Mid-year Rate Base	1159	2301	2307	2298	46485	88764	84242	79721	75201
Revenue Requirement:									
Debt	50%	@	15%						
Equity	50%	@	19%						
Cost of Debt	87	173	173	172	3486	6657	6318	5979	5640
Return on Equity	110	219	219	218	4416	8433	8003	7573	7144
Earned Return	197	391	392	391	7902	15090	14321	13553	12784
Expenses:									
O&M	925	1961	2079	2203	1136	703	745	789	837
Property Taxes	75	150	532	1156	1382	1465	1553	1646	1745
Depreciation	0	120	120	120	120	4501	4501	4501	4501
Diesel Generation:									
Unit Cost (c/l):									
Cost (1984$)	37.10	37.10	37.20	37.30	37.40	37.50	37.70	37.70	37.90
Cost (Current $)	37.10	39.33	41.80	44.42	47.22	50.18	53.48	56.69	60.41
Consumption (10E6 l)	8.58	17.15	17.15	16.55	8.70	0.85	0.85	0.85	0.85
Energy (% of load)	100.0%	100.0%	100.0%	100.0%	52.6%	5.2%	5.2%	5.2%	5.2%
Cost of Fuel	3181	6744	7168	7352	4108	427	455	482	513
Water Licence Fees:									
Unit Cost:									
Real Growth		0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
Demand ($/kW)	2.85	3.02	3.21	3.40	3.61	3.83	4.07	4.32	4.58
Commodity ($/MWh)	2.00	2.12	2.25	2.39	2.54	2.69	2.85	3.03	3.21
Licenced Capacity (MW)	0	0	0	0.0	12.0	12.0	12.0	12.0	12.0
Fees	0	0	0	0	113	194	206	218	231

TABLE 4.3 - Part 1 (Continued)

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
1.6895	1.7908	1.8983	2.0122	2.1329	2.2609	2.3966	2.5404	2.6928	2.8543	3.0256	3.2071	3.399[illegible]
88826	88826	88826	88826	88826	88826	88826	88826	88826	88826	88826	88826	88826
1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
71061	66619	62178	57737	53296	48854	44413	39972	35530	31089	26648	22206	17765
480	420	360	300	240	180	120	60	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
4441	4441	4441	4441	4441	4441	4441	4441	4441	4441	4441	4441	4441
60	60	60	60	60	60	60	60	0	0	0	0	0
66619	62178	57737	53296	48854	44413	39972	35530	31089	26648	22206	17765	13324
420	360	300	240	180	120	60	0	0	0	0	0	0
69290	64789	60288	55786	51285	46784	42282	37781	33310	28868	24427	19986	15545
1394	1933	2684	2618	2554	2492	2432	2375	2309	2258	2210	2164	2122
70684	66722	62971	58404	53839	49276	44715	40156	35619	31128	26837	22150	17ee7
5301	5004	4723	4380	4038	3696	3354	3012	2671	2334	1998	1661	1325
6715	6339	5982	5548	5115	4681	4248	3815	3384	2957	2531	2104	1678
12016	11343	10705	9929	9153	8377	7601	6827	6055	5291	4528	3766	3003
887	940	997	1056	1120	1187	1258	1334	1414	1499	1588	1684	1785
1850	1961	2079	2203	2336	2476	2624	2782	2949	3126	3313	3512	3723
4501	4501	4501	4501	4501	4501	4501	4501	4441	4441	4441	4441	4441
38.20	38.40	38.60	38.90	39.10	39.40	39.60	39.90	40.10	40.40	40.70	40.90	41.20
64.54	68.77	73.27	78.27	83.40	89.08	94.90	101.36	107.98	115.32	123.14	131.17	140.06
0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
549	585	623	665	709	757	807	862	918	980	1047	1115	1191
0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
4.86	5.16	5.47	5.80	6.16	6.53	6.93	7.36	7.81	8.28	8.79	9.32	9.89
3.41	3.62	3.84	4.07	4.32	4.59	4.87	5.16	5.48	5.81	6.17	6.54	6.94
12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
246	261	276	293	311	330	350	372	395	419	444	471	500

COLUMBIA PACIFIC

TABLE 4.3 - Part 2

Cassiar Small Hydro - Utility Revenue Requirement ($000)
Scenario:12 MW Hydro

Fiscal Year Beginning Jan 1	1984	1985	1986	1987	1988	1989	1990	1991	1992
Inflation Rate	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Inflation Factor (1984=1)	1.0000	1.0600	1.1236	1.1910	1.2625	1.3382	1.4185	1.5036	1.5938
Lube Oil:									
Unit Cost ($/l):									
Cost (1984$)	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
Cost (Current $)	1.45	1.54	1.63	1.73	1.83	1.94	2.06	2.18	2.31
Volume (kl)	88	176	176	140	27	27	27	27	27
Cost	128	271	287	242	49	52	56	59	62
Total Expenses	4309	9246	10185	11073	6909	7342	7515	7696	7891
Income Taxes:									
Tax Rate	50%	50%	50%	50%	50%	50%	50%	50%	50%
CCA Base:Hydro 25%	0	4240	22472	35730	9469	0	0	0	0
Hydro 50%	0	0	4240	22472	35730	9469	0	0	0
Hydro 25%	0	0	0	4240	22472	35730	9469	0	0
Diesel 6%	600	1164	1094	1029	967	909	854	803	755
CCA:Hydro	0	1060	7738	21229	25850	13667	2367	0	0
Diesel	36	70	66	62	58	55	51	48	45
Accumul Losses	0	0	717	8182	29134	50506	51294	41208	29181
Applied Losses-Current	0	0	0	0	0	0	10086	12027	11600
-Previous	0	148	0	0	0	0	0	0	0
Current Tax Loss	0	865	7464	20952	21372	788	0	0	0
Income Taxes	74	(74)	0	0	0	0	0	0	0
Required Revenue	4580	9563	10578	11464	14811	22432	21836	21249	20675
Waste Heat Revenue:									
Diesel Recovery Factor	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Revenue	318	674	717	735	411	43	45	48	51
Load (GWh)	29.57	59.13	59.13	57.93	57.93	57.93	57.93	57.93	57.93
Elec Cost (mills/kWh)	144.2	150.3	166.8	185.2	248.6	386.5	376.2	366.0	356.0
(1984 mills/kWh)	144.2	141.8	148.4	155.5	196.9	288.8	265.2	243.4	223.4
Lev Elec Cost (1984 mills/kWh)									
5%	144.2	142.6	144.8	147.7	157.6	178.6	190.1	196.1	198.7
10%	144.2	142.6	144.8	147.4	156.5	175.5	185.8	191.3	193.8

TABLE 4.3 - Part 2 (Continued)

18-Dec-84

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
1.6895	1.7908	1.8983	2.0122	2.1329	2.2609	2.3966	2.5404	2.6928	2.8543	3.0256	3.2071	3.3996
1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
2.45	2.60	2.75	2.92	3.09	3.28	3.48	3.68	3.90	4.14	4.39	4.65	4.93
27	27	27	27	27	27	27	27	27	27	27	27	27
66	70	74	79	84	89	94	99	105	112	118	126	133
8099	8318	8550	8799	9060	9340	9635	9950	10221	10576	10952	11349	11772
50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
710	667	627	589	554	521	489	460	433	407	382	359	338
0	0	0	0	0	0	0	0	0	0	0	0	0
43	40	38	35	33	31	29	28	26	24	23	22	20
17581	6407	0	0	0	0	0	0	0	0	0	0	0
11174	6407	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
0	4,393	10,446	10,014	9,583	9,151	8,720	8,289	7,799	7,374	6,943	6,524	6,093
20115	24053	29701	28742	27796	26868	25956	25065	24076	23241	22429	21638	20875
10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
55	58	62	67	71	76	81	86	92	98	105	111	119
57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93	57.93
346.3	414.2	511.6	495.0	478.6	462.5	446.7	431.2	414.0	399.5	385.4	371.6	358.3
205.0	231.3	269.5	246.0	224.4	204.6	186.4	169.7	153.8	140.0	127.4	115.9	105.4
199.2	201.6	206.1	208.5	209.3	209.1	208.1	206.5	204.6	202.4	200.1	197.6	195.1
194.6	196.7	200.3	202.3	203.1	203.2	202.7	201.8	200.7	199.5	198.1	196.8	195.4

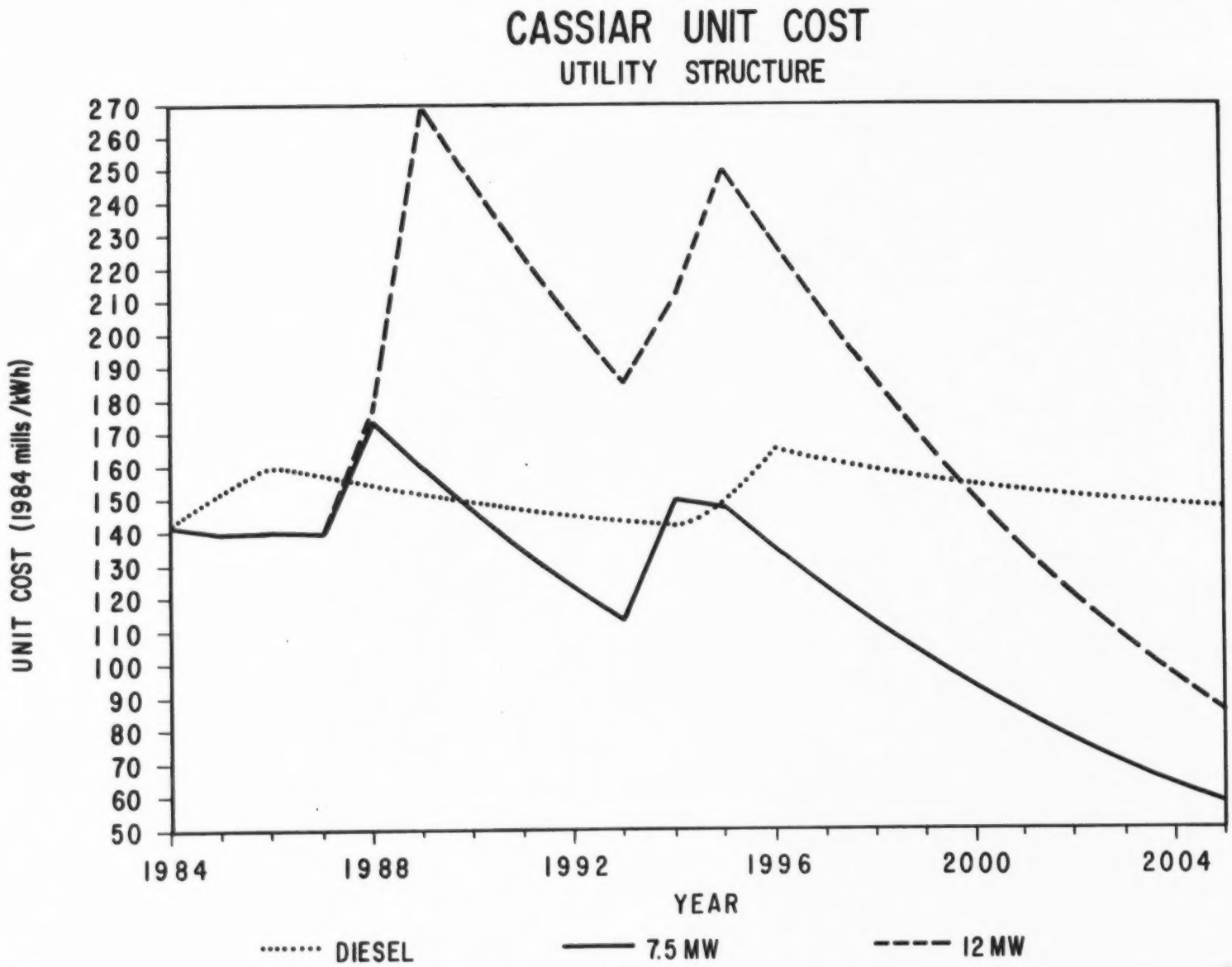

CASSIAR UNIT COST
UTILITY STRUCTURE
UNIT COST (1984 mills/kWh)
270
260
250
240
230
220
210
200
190
180
170
160
150
140
130
120
110
100
90
80
70
60
50
1984
1988
1992
1996
2000
2004
YEAR
DIESEL
7.5 MW
12 MW

TABLE 4.4

SENSITIVITY ANALYSIS - 7.5 MW HYDRO

Sensitivity	Description	Difference in Levellized Rates* (1984 Mills/kW.h) Real Discount Rate 5%	10%
Base Case	Diesel mill rate	155.4	155.1
	7.5 MW hydro base case mill rate	139.5	144.8
	Difference	15.9	10.3
1	7.5 MW hydro with 7.5 MW hydro property tax set equal to Diesel property tax:		
	Difference	25.1	19.0
2	7.5 MW hydro with Cost of Debt reduced by 1% (to 14% & 18% respectively):		
	Difference	19.6	13.9
3	7.5 MW hydro with no water license fees:		
	Difference	17.7	11.9
4	7.5 MW hydro without Class 34 CCA		
	Difference	1.0	-7.4

* Difference between levellized mill rates of the Diesel alternative and the 7.5 MW hydro alternative, levellized for period 1984-2005.

A further source of exemption is found in Section 103 under which the Commission may exempt a person from the operation of an order, rule or regulation made under the Act or may exempt a person with the prior approval of the Lieutenant Governor in Council from the application of any or all provisions of the Act. These exemptions under Section 103 do not apply to Part 2 which deals with regulated energy projects and energy removal.

Clearly there is no lack of opportunity to obtain exemption from the provisions of The Utilities Commission Act. The process of actually obtaining the desired exemption would likely be initiated by directing a request to the Minister.

The response to an applicant's request for exemption under The Utilities Commission Act is affected by the provincial government's energy policy with respect to small hydro development. The current (mid-1984) provincial government policy is to encourage development of small hydro in remote, resource areas such as northwest British Columbia. The Minister of Energy, Mines and Petroleum Resources recently described this policy as follows:

> "Another part of the electrical strategy is to give the private sector a bigger piece of the action. We intend to encourage the private development of small and mid-sized hydroelectric sites, geared to industrial development in remote areas--for example, in resource-rich northwestern B.C.".

Accompanying the request or forming a part of it could be a brief or report which addresses the project concept and its justification. Incorporated in the document could be an economic comparison with other practical generating alternatives; a financial plan and capital structure (ownership) for the utility; a suggested rate structure together with some demonstration that the rates are non-discriminatory; evidence of continuity of service over the proposed life of the development (i.e., that users would not be placed in jeopardy should Brinco curtail or discontinue its mining operation at Cassiar); comment on the technical feasibility of the concept and such other information as may be deemed relevant to supporting an argument for exemption from The Utilities Commission Act.

The Utilities Commission Act also addresses the question of permits and approvals. As already noted, Part 2 of the Act deals with regulated energy projects and energy removal certificates. In respect of hydroelectric developments, the Act defines a regulated (energy) project as one having a capacity of 20 megawatts or more. Entities wishing to develop a regulated project can expect to go through a fairly rigorous process involving the preparation and submission of a comprehensive energy project certificate application (EPCA). This application, after careful review by the appropriate government ministries, could be forwarded to the Utilities Commisssion by the Minister of Energy, Mines and Petroleum Resources (MEMPR) for a review. In all likelihood, the review would entail a public hearing.

---

1) Speech made by The Honourable Stephen Rogers, Minister of Energy, Mines and Petroleum Resources, to the Northwest Public Power Association Annual Meeting, Victoria, May 31, 1984.

Non-regulated (less than 20 megawatt) hydroelectric developments are subject to a somewhat different approval processs. The initiating action is an application submitted under The Water Act to the Water Management Branch, Ministry of Environment (MOE) for a water licence. The application involves completing a relatively short prescribed form and filing it with the Water Recorder in the Water District in which the project is proposed. Posting of the application at certain specified locations is also required. If Crown Land is needed for construction or flooding, the applicant will be required to apply to the Water Comptroller for a permit to use the land. Licence fees are payable in advance. Technical and environmental information in support of the application will also be needed.

As part of the administrative and technical evaluation process, notice of receipt of the application is sent to the Fisheries and Wildlife Branches of the MOE, Federal Deparment of Fisheries and Oceans (DFO) and B.C. Hydro. The referral to B.C. Hydro is primarily for purposes of information, not for any form of approval.

The objectives of the review by the Water Management Branch are threefold. First, the works to be constructed must be of sound design and provide an acceptable margin of public safety; second, environmental impacts must, with mitigation and compensation if necessary, be acceptable to the appropriate government agencies; and third, the rights and interests of private parties affected by the development must be addressed.

The first of the above requirements will be satisfied by the applicant producing sufficient geological, hydrological, topographical, design and other data for examination by the technical experts of the Water Management Branch.

The second issue may require the preparation of an environmental impact statement in which the anticipated negative effects of the project on fish, wildlife, water quality and other environmental features are discussed and proposals for mitigating against and compensating for the impacts are advanced. Close liaison with the appropriate government agencies such as Fisheries and Wildlife Branches and the Waste Management Branch of MOE, the Ministry of Forests, the Ministry of Land, Parks, and Housing, and, possibily, DFO is advantageous at this stage.

Finally, the rights and interests of private parties will be identified, usually by the applicant and dealt with, probably through negotiation.

While the process described above may appear somewhat ill-defined with the applicant being responsible for picking his way through a rather complex process, such is not the case. Officials of the Water Management Branch will guide the applicant through the government approval process.

4.4 Summary

Alternative organizational structures for a regional utility can have differential tax and financing implications which could prove significant in initiating a project of this type. The conventional utility structure may be less attractive in terms of the level of equity financing required by the proponent and the potential absence of certain tax write-offs (e.g. investment tax

credit). On the other hand, the conventional structure could be more successful in attracting new customers, in obtaining suitable financing and in dealing with government and regulatory officials on tax and policy matters.

The financial analysis of the existing diesel and small hydro options, assuming a conventional utility structure, indicates that the 7.5 MW project is preferable under a base case which assumes existing tax law and Class 34 CCA's. The relative advantage of the 7.5 MW project under the base case erodes without the Class 34 CCA's. On the other hand, the relative advantage of 7.5 MW project under the base case improves markedly with assumed reductions in taxes (property taxes, water licence fees) and the utility's cost of capital.

The review of regulatory implications of a regional small hydro utility indicates the requirement for a long term commitment to service regardless of the organizational structure. The utility's exemption status from regulation requires evidence that the small hydro project is economically efficient, ensures continuity of service (particularly to third parties), applies non-discriminatory prices, is financially feasible, and is environmentally acceptable. These requirements certainly imply a social responsibility for providing continuous service over the long term. Private sector proponents should recognize the limits placed on their flexibility in terms of curtailing or eliminating service in the event that it became privately (rather than socially) desirable to do so.

5. CONCLUSIONS

1. Preliminary Social Benefit-Cost Analysis

Two potential small hydro systems (7.5 MW, 12 MW) were assessed on a preliminary basis to determine their broad economic efficiency relative to the existing diesel system. The analysis indicated that the 7.5 MW case would yield higher net social benefits to Canada/British Columbia in comparison with the existing diesel system. The opposite is likely true for the 12 MW case.

2. Regional Utility Concept

2.1 Organizational Structure

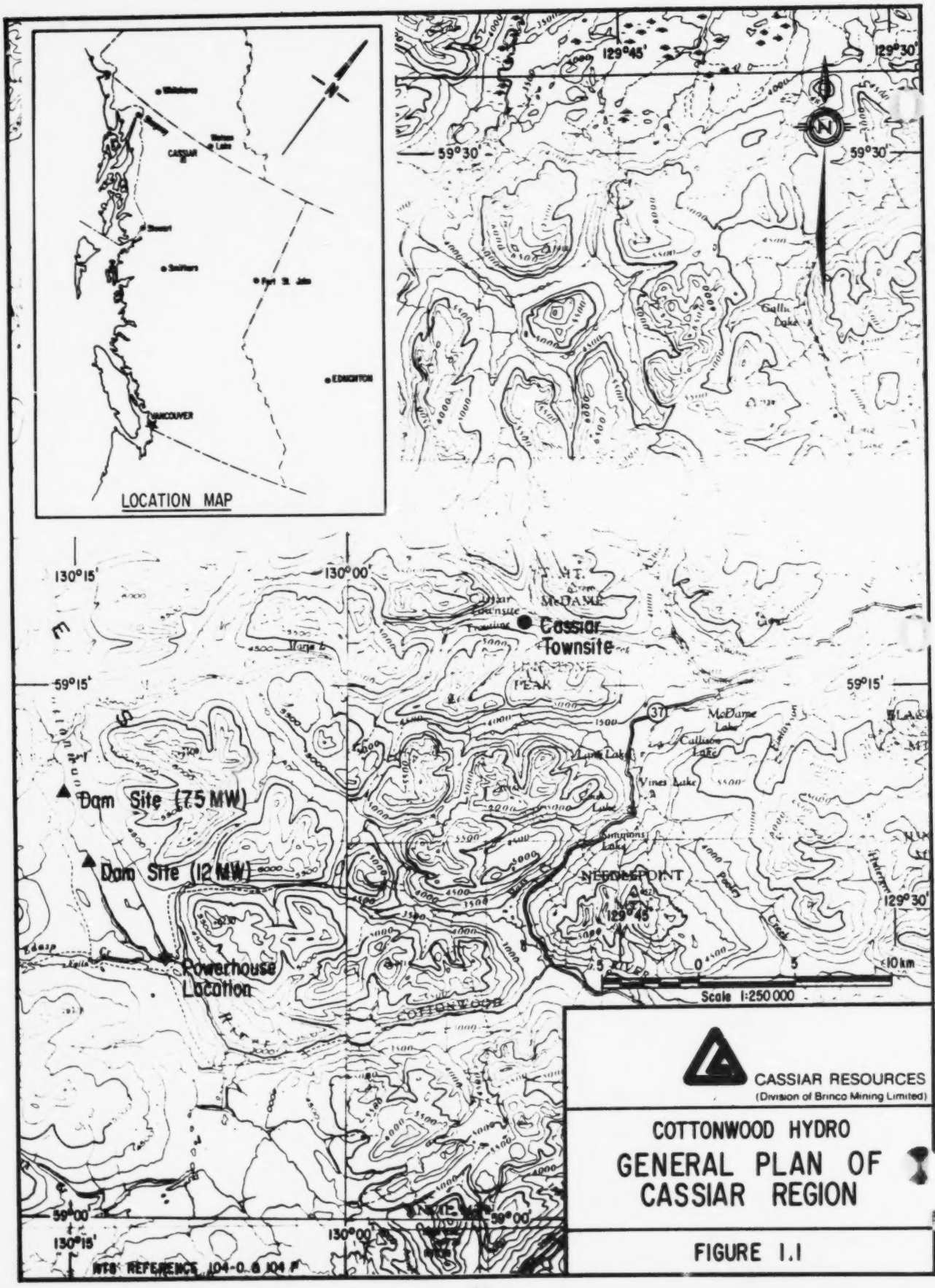
The analysis identified three potentially viable structures: the conventional private utility organization, a utility directly owned by the private resource company and a limited partnership framework. The alternative structures could have different tax and financing implications which could prove significant in initiating the project. The conventional structure may be less desirable in terms of the required level of direct equity financing by the proponent and the possible non-eligibility of certain tax write-offs (e.g., investment tax credit). The conventional structure could, on the other hand, be advantageous to the extent that it is more attractive to lenders, potential customers and government.

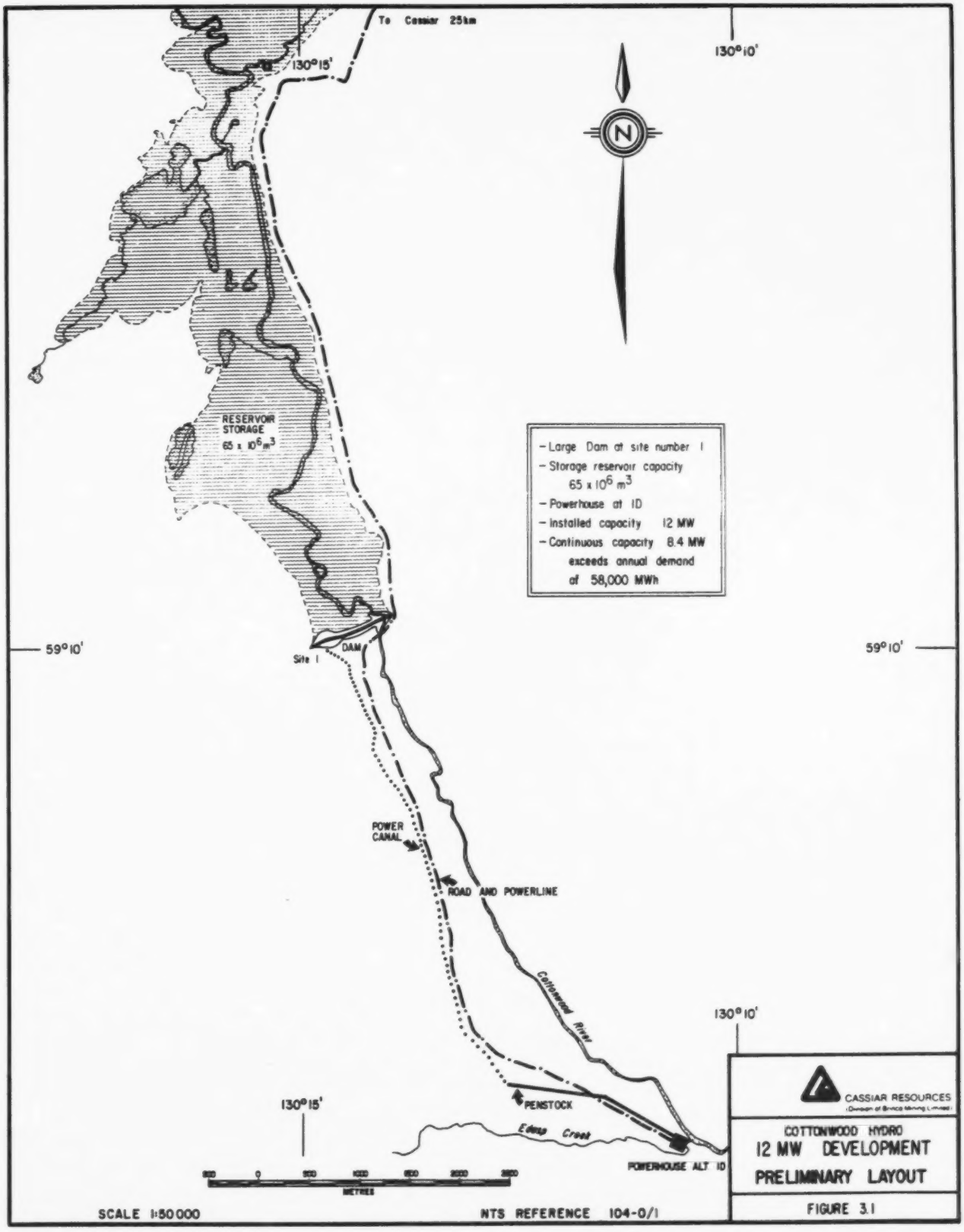
2.2 Financial Feasibility

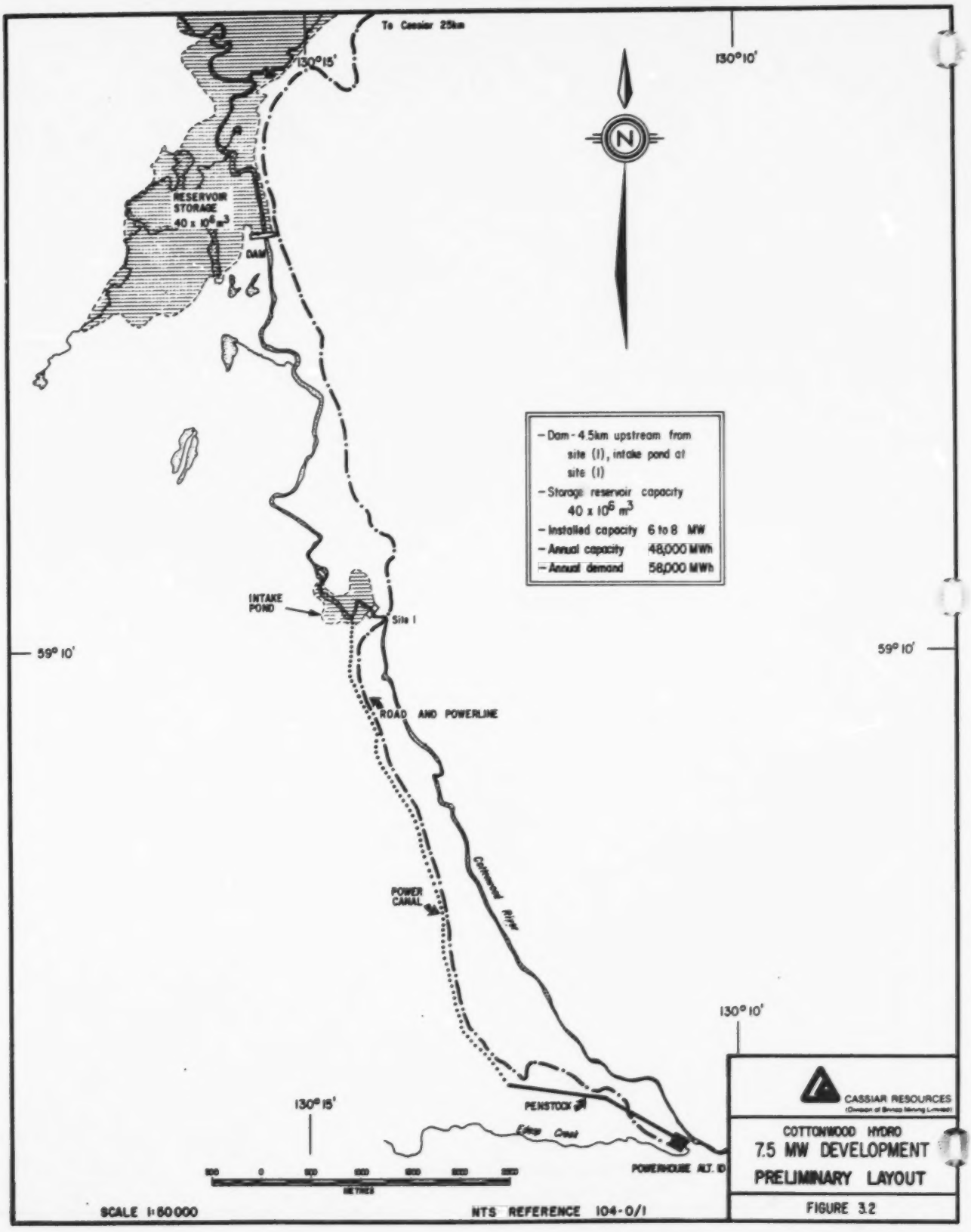
The 7.5 MW project is more attractive relative to the existing diesel system under a base case which assumes existing tax law and Class 34 CCA's. This relative advantage of the 7.5 MW project erodes without the Class 34 CCA's. However, the financial attractiveness of the 7.5 MW project improves markedly when the Class 34 CCA's are augmented with assumed reductions in property taxes, water licence fees or the utility's cost of capital.

2.3 Regulatory Implications

A regional small hydro utility may be exempted by the existing utility regulation process in British Columbia but the social obligations attendant to regulated utilities would still have to be met. The public interest requirements for regulated utilities (i.e., long-term continuity of service to customers, non-discriminatory pricing, economic and financial viability, environmental acceptability, etc.) would likely have to be demonstrated in order to obtain exemption status. The social obligations may impede the planning and decision-making flexibility of a proponent resource company (e.g., curtailment of operations) therein introducing a dimension of additional risk to the proponent.


LOCATION MAP
Cassiar Townsite
Dam Site (75 MW)
Dam Site (12 MW)
Powerhouse Location
McDAME
Gallic Lake
Vines Lake
Simmons Lake
NEEDLE POINT
COTTONWOOD
129°45'
129°30'
59°30'
59°15'
59°00'
130°15'
130°00'
0 5 10 km
Scale 1:250 000
CASSIAR RESOURCES
(Division of Brinco Mining Limited)
COTTONWOOD HYDRO
GENERAL PLAN OF CASSIAR REGION
FIGURE 1.1


To Cassiar 25km
130°15'
130°10'
N
RESERVOIR STORAGE 65 x 10⁶ m³
- Large Dam at site number 1
- Storage reservoir capacity 65 x 10⁶ m³
- Powerhouse at ID
- Installed capacity 12 MW
- Continuous capacity 8.4 MW exceeds annual demand of 58,000 MWh
59°10'
DAM
Site 1
POWER CANAL
ROAD AND POWERLINE
Cottonwood River
PENSTOCK
Edna Creek
POWERHOUSE ALT ID
METRES
SCALE 1:50000
NTS REFERENCE 104-O/1
CASSIAR RESOURCES
COTTONWOOD HYDRO
12 MW DEVELOPMENT
PRELIMINARY LAYOUT
FIGURE 3.1


To Cassiar 25km
130°15'
130°10'
N
RESERVOIR STORAGE 40 x 10⁶ m³
DAM
- Dam - 4.5km upstream from site (1), intake pond at site (1)
- Storage reservoir capacity 40 x 10⁶ m³
- Installed capacity 6 to 8 MW
- Annual capacity 48,000 MWh
- Annual demand 58,000 MWh
INTAKE POND
Site 1
59° 10'
ROAD AND POWERLINE
Cottonwood River
POWER CANAL
PENSTOCK
Edney Creek
POWERHOUSE ALT. ID
METRES
SCALE 1:50000
NTS REFERENCE 104-O/1
CASSIAR RESOURCES
(Division of Barrier Mining Limited)
COTTONWOOD HYDRO
7.5 MW DEVELOPMENT
PRELIMINARY LAYOUT
FIGURE 3.2